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Minimum and Maximum System Demand Forecasts – Methodology and Results Report

Prepared by ENERGEIA for
Power and Water Corporation

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ENERGEIA

Executive Summary

Power and Water Corporation (PWC), as the network service provider for the Northern Territory (NT), is obligated under the National Electricity Law and Northern Territory National Electricity Rules (NEL and NT NER) to ensure their system and supply of electricity is run efficiently, safely, reliably, and securely whilst maintaining quality and minimising the price impacts to electricity consumers[1].

As part of this obligation, PWC must provide system demand forecasts, which satisfy the Australian Energy Regulator's (AER's) regulations surrounding network planning, capital expenditure and pricing[2]. Additionally, these forecasts serve internal business requirements for finance, pricing and network planning business units[3].

Demand itself and the ability to forecast it is impacted by a variety of evolving demand forecast drivers. These include the rapid growth of behind-the-meter (BTM) solar PV and battery storage, as well as continued electrification of buildings and the emergence of electric vehicle (EV) transportation, and the COVID-19 global pandemic. As a result, industry forecasting practices are changing.

PWC engaged Energeia to produce system forecasts of annual minimum and maximum demand for each region in PWC's network to 2031-32. These regions are Darwin-Katherine, Alice Springs, and Tennant Creek. The forecasts were to be accompanied by sufficient documentation (i.e., this report) to withstand AER scrutiny, and in particular were to demonstrate that the forecasts satisfy PWC's key NT NER obligations, namely that they present a realistic expectation of demand.

Scope and Approach

Energeia worked closely with PWC to develop the following scope and approach for this project:

1. **Document Requirements –** Energeia reviewed the regulatory framework, recent regulatory determinations and engaged with stakeholders to define the key forecasting requirements
2. **Identify Industry Best Practices** – Energeia benchmarked peer-Distributed Network Service Provider (DNSP) forecasting methodologies from recent regulatory cycles to identify industry best practices.
3. **Develop Procedure** – Based on the outcomes from steps 1 and 2, Energeia developed a best practice, fit-for-purpose procedure for producing demand forecasts.
4. **Gather Inputs** – Energeia gathered the most recent inputs from PWC, as well as a variety of external inputs from reputable sources, for use in the forecasting methodology optimisation and forecasts.
5. **Forecast Demand** – Energeia implemented the developed forecasting methodology to produce forecasts to 2031-32 of maximum and minimum system demand for each region in PWC's network.
6. **Model Validation** – Energeia worked closely with PWC subject matter experts (SMEs) to validate the methodology, inputs, and outputs of the demand forecasting model.
7. **Documentation –** Energeia provided documentation for the produced forecasts, including presentation materials and this report.

Key Requirements

The NT NER covers the key regulatory requirements for PWC in regard to minimum and maximum demand forecasting. NT NER Section 6.5.7 requires capital expenditure forecasts to be provided for the relevant regulatory period in building block proposals. These proposals must meet or manage expected demand, and the AER must accept the capital expenditure forecasts if they reflect a realistic expectation of demand[4].

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[1] National Electricity (South Australia) Act 1996, Part 1, Section 7 – National Electricity Objective

[2] See Sections 1.1.1, 1.1.2, and 1.1.3

[3] See Section 1.2

[4] National Electricity Rules as In Force in the Northern Territory Version 96 – Section 6.5.7(a) and 6.5.7(c)

NT NER Section 6.18.5 covering Network Pricing Principles requires expected tariff revenue to reflect the efficient cost of serving the customer[5], which require an accurate minimum and maximum demand forecast to achieve.

Energeia worked with PWC to identify the key business requirements for minimum and maximum demand forecasts. System minimum and maximum demand forecasts are a key component of PWC's finance, pricing, and network planning functions. They are one of the key forecasts used in capital and operating expenditure program development and are also used to reconcile demand forecasts PWC produce at levels below the system (i.e., sub-transmission, zone substation and feeder levels).

Industry Best Practice

Energeia reviewed over 53 documents from AEMO and Australian DNSPs regarding their network forecasting methodologies including connections and min/max demand. This was completed to ensure that the demand forecasting methodology selected for this project are considered best practice based on previous regulator feedback to DNSPs.

Energeia's research found that the industry appears to be moving from a trend-based forecasting approach for connections and demand to a more sophisticated approach using multifactor regression, and more novel techniques, including agent-based simulation. AEMO has updated its demand forecasting methodology to now be based on a combination of a machine learning model for hourly loads and an extreme value model.

Other key trends in demand forecasting include:

- Consideration of electric vehicle, battery and demand management forecasts;
- The emergence of using spatial forecasts to improve connection and demand forecast accuracy;
- The inclusion of minimum demand forecasting; and
- Accounting for demand shocks, e.g. COVID, temporary / permanent mine shutdowns.

Energeia considered the above key findings when developing and implementing a best practice, fit-for-purpose regional system min/max demand forecasting methodology for PWC.

Methodology

The methodology that Energeia developed and implemented utilised dynamically optimised, multi-factor regression as the core forecasting technique, consisting of the following key steps:

1. **Develop Demand Forecasting Procedure** – Energeia developed a fit-for-purpose demand forecasting procedure that satisfied the key requirements and reflected industry best practice
2. **Data Gathering and Processing** – Energeia processed load profiles provided by PWC for outages, historical spot loads and weather normalisation.
3. **Forecast Model Optimisation –** Energeia identified the optimal model parameters given fitness, sign and p-value, then post-processed spot and EV loads and adjusted to FY22 actuals.
4. **Validate Optimised Results** – Energeia reviewed the technically optimised forecasts against historical trends and validated them with comparisons to published forecasts[6] and sharing with PWC stakeholders prior to finalisation.

A detailed discussion of the above steps and key inputs is presented in Section 3 and Section 4.

[5] Ibid. Section 6.18.5(g)

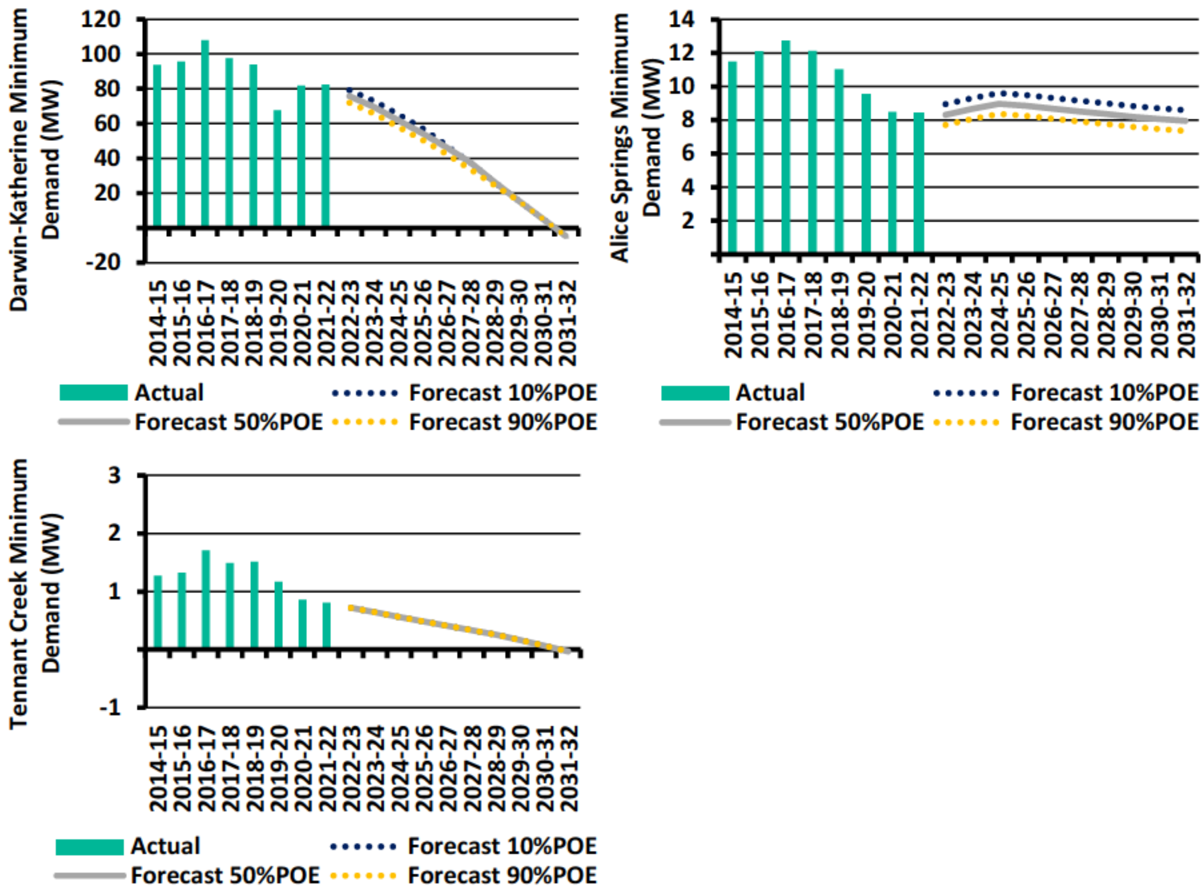
[6] AEMO for NT Utilities Commission, 2022 Northern Territory Electricity Outlook Report Data

Results

Minimum demand forecasts for each region in PWC's network is given in Figure ES1, which shows minimum demand falling over the period, primarily driven by solar PV uptake reducing grid load during the middle of the day. Key results are as follows:

- The timing of maximum demand is shifting to the middle of the day, driven by behind-the-meter solar PV generation reducing system demand during peak sun hours.
- Darwin-Katherine minimum demand is forecast to fall significantly from 82.2 MW in 2021-22 to -4.98 MW in 2031-32, with the minimum demand occurrence shifting from early morning (4am) to the middle of the day (3pm/1pm).
- Alice Springs minimum demand is forecast to rise to 8.96 MW in 2024-25 and from 8.42 MW in 2021-22 and then fall to 7.95 MW in 2031-32, noting minimum demand is continuing to be observed in the middle of the day (1pm).
- Tennant Creek minimum demand is forecast to fall significantly from 0.81 MW in 2021-22 to -0.03 MW in 2031-32, with the minimum demand occurrence continue to occur at either midday (2pm) or early morning (1-2am)

Figure ES1 – Historical and Forecast Minimum Demand by Region



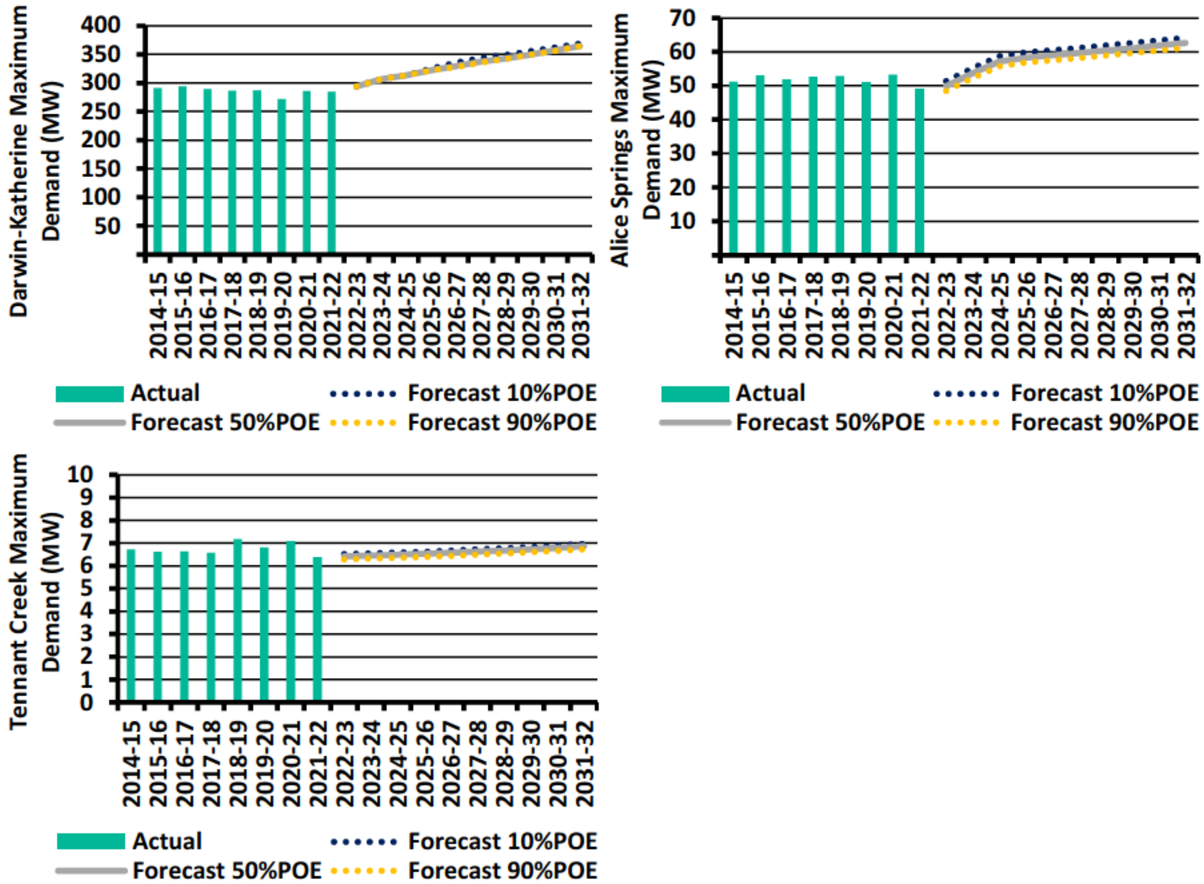
Source: Energeia Analysis, PWC

Forecast maximum demand for each region in PWC's network is reported in Figure ES2, which sees maximum demand increasing across PWC's network, driven by increasing connections and the addition of spot loads. EVs are not predicted to have a significant impact on system-level maximum demand.

Key results include:

- The timing of maximum demand is shifting into the evening, driven by behind-the-meter solar PV generation supressing grid demand during the historical peak consumption periods of the afternoon.
- Darwin-Katherine maximum demand is forecast to increase significantly from 284.6 MW in 2021-22 to 364.4 MW in 2031-32, with the maximum demand occurrence shifting from afternoon (4pm) to the early evening (7pm).
- Alice Springs maximum demand is forecast to increase sharply until 2024-25, and more steadily thereafter, from 48.8 MW in 2021-22 to 62.65 MW in 2031-32, noting maximum demand is continuing to be observed in the early evening, shifting to 5 or 6pm.
- Tennant Creek maximum demand is forecast to increase modestly 6.39 MW in 2021-22 to 6.86 MW in 2031-32, noting maximum demand is continuing to be observed in the early evening, shifting to 5pm.

Figure ES2 – Historical and Forecast Maximum Demand by Region



Source: Energeia Analysis, PWC

Further detail regarding these forecasts, along with a comparison to the NT Utility Commission forecast of demand, can be found in Section 5.

A refresh of forecasts using FY22 actuals, including rerunning the regression methodology presented here, will be completed after submission of the Initial Regulatory Proposal.

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Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information and guidance from Power and Water Corporation, and other publicly available information. To the extent these reliances have been made, Energeia does not guarantee nor warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party, with the exception of the Australian Energy Regulator, should use or rely on the report for any purpose.

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1. Background

Power and Water Corporation (PWC), as the network service provider for the Northern Territory (NT), must maintain their network infrastructure so that they are able to provide their customers with access to electricity[7]. For the prudent, efficient and reliable[8] supply of electricity, the network must have the capacity to support the peak demand of its customers at all levels of the network. Minimum demand can additionally put strain on the network, particularly with the continued growth of behind-the-meter PV electricity exports which PWC are required to support[9].

As a result, forecasting the reasonably likely minimum and maximum demand in the network over the next regulatory period is essential for informing prudent and efficient infrastructure planning and expenditure.

1.1. Regulatory Requirements

PWC are regulated by the Australian Energy Regulator (AER) under the NT National Electricity Rules (NT NER). The NT NER sets out the regulations governing network forecasts, which are detailed in the following sections.

1.1.1. Capital Expenditure

The NT NER Section 6.5.7[7] states the demand forecasting requirements related to capital expenditure forecast justification, which is excepted as follows:

> *(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):*
>
> > *(1) meet or manage the expected demand for standard control services over that period;*
>
> *…*
>
> *I The AER must:*
>
> > *(1) subject to subparagral(c)(2), accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (the capital expenditure criteria):*
> >
> > > *…*
> > >
> > > (iii) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Energeia defines realistic expectation as being the expectation formed by a reasonable person given the circumstances and information available, which was addressed by the application of industry best practice methods and appropriate inputs. Appropriate in this case is defined by Energeia as the use of unbiased historical inputs consistent with the duration of the output, but also considering major issues in the last five years like COVID.

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[7] National Electricity Rules as In Force in the Northern Territory Version 96, Clause 5.2.1(a)

[8] To the extent governed by the value of customer reliability, see https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Factsheet%20-%20December%202019.pdf

[9] National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021

1.1.2. Pricing

Forecasts are also used in the Tariff Structure Statement (TSS), which forms part of the IRP. Regarding the use of forecasts in the tariff structure statement, the NER state in Section 6.18.5[10] that:

> *(g) The revenue expected to be recovered from each tariff must…*
>
> *(17) (1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff.*

A reasonably realistic demand forecast is therefore a key input to the development of a NT NER compliant TSS.

Forecast maximum demand is also a key input to the development of Long-Run-Marginal-Cost (LRMC) estimates using the Average Incremental Cost (AIC) methodology.

1.1.3. Network Planning

Although not relevant for development of demand forecasts used to drive capex forecasts as part of the Initial Regulatory Proposal (IRP), the NT NER also includes forecasting requirements as part of the Distribution Annual Planning process, which are listed in NT NER Section 5.13.1:[10]

(b) The minimum forward planning period for the purposes of the distribution annual planning review is 5 years

…

(d) Each Distribution Network Service Provider must, in respect of its network:

> *(1) prepare forecasts covering the forward planning period of maximum demands for:*
>
> > *(i) sub-transmission lines;*
> >
> > *(ii) zone substations; and*
> >
> > *(iii) to the extent practicable, primary distribution feeders, having regard to:*
> >
> > *(iv) the number of customer connections*
> >
> > *(v) energy consumption; and*
> >
> > *(vi) estimated total output of known embedded generating units.*

Energeia ensured that the proposed forecasting methodology met these requirements and could be applied at lower levels of the grid, helping to underpin an internally consistent approach to system and spatial level forecasting.

1.2. Business Requirements

Energeia worked with PWC to identify the key business requirements for a range of forecasts, including the system minimum and maximum forecasts that pertain to this report. Table 1 shows the forecasts needed by business function and highlights that system demand forecasts are one of the key forecasts that underpin PWC's system planning, capital and operating expenditure forecasting, finance and pricing.

[10] National Electricity Rules as In Force in the Northern Territory Version 96

Table 1 – PWC Business Requirements by Forecast Type

Function	New Conns	Total Conns	Spatial Max Demand	Spatial Min Demand	System Max Demand	System Min Demand	Sales (MWhs)	Solar PV	Batteries	EV Charging Impacts
Regulation	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Pricing	✓	✓	✓	✓	✓	✓	✓			
Finance	✓	✓			✓	✓	✓			
Network Planning	✓	✓	✓	✓				✓	✓	✓
Metering	✓							✓	✓	
Demand Management	✓	✓	✓	✓				✓	✓	✓
Supply Chain	✓	✓	✓	✓				✓	✓	✓
System Planning	✓	✓			✓	✓	✓	✓	✓	✓

Source: Energeia, PWC
Note: Purple indicates the demand forecast covered in this report

As Table 2 summarises, PWC's regional demand forecasts form the basis of other forecasts used for planning at different levels within the network and for reconciliation with Corporate Regional forecasts. The business requires ten-year forecasts, which are longer than required for the regulatory proposal or for the Annual Planning Report.

Table 2 – Power and Water Business Requirements for Network Demand Forecasting

Forecast	Period	Purpose
Region	10* years	Overall demand, based on economic considerations, for comparison with corporate forecasts and lower-level forecasts.
Sub transmission substations (132/66 kV or 66/22 kV or 66/11 kV), transmission connected customers and generators		To plan the development of the transmission network and existing and new transmission connected substations.
Zone and Modular substations (132/22 kV or 66/22 kV or 66/11 kV)	10* years	To plan the development of the sub transmission network and existing and new sub transmission connected zone substations.
High Voltage Distribution Feeders (22 or 11 kV)		To plan the development of the High Voltage network.
Customer connections (all voltages)		Both above

Source: Energeia, PWC
* Current year plus. i.e., = 1+10
Note: Purple indicates the demand forecasts covered in this report

Energeia also notes that demand forecasts are likely a key component in PWC's revenue forecasting, which is only needed on a rolling 3-year basis for the Statement of Corporate Intent (SCI).

1.3. *Evolving Forecasting Drivers*

Demand is increasingly being impacted by a variety of emerging drivers which have an effect on both current and future regional minimum and maximum demand trends, including:

- **Behind-the-Meter Solar PV** – Rooftop PV installations have grown significantly and will continue to grow in future[11], reducing household consumption and exporting excess generation to the grid. This can cause the timing of maximum demand to be shifted outside of daylight hours. Conversely, PV generation during peak sunlight hours (where residential demand is typically low) creates falling operational demand and can shift the timing of minimum demand to during solar hours.
- **Building and Transport Electrification** – Building electrification has been driven by climate policy (e.g. Net Zero by 2050), investor benefits, health and safety benefits, risk reduction, and consumer preferences[12] causing industrial and household appliances to shift from fossil fuels to electrified power sources and adding new building loads to the network. Additionally, new sources of electricity demand are emerging in the transportation sector through the uptake of Electric Vehicles (EVs), which adds charging loads to the network.
- **COVID-19 Pandemic** – The global pandemic has impacted international and domestic economies and societal behaviours significantly[13], including electricity demand[14]. Uncertainty remains surrounding how long behavioural shifts will last, and the extent to which demand will return to pre-pandemic dynamics. This adds an additional challenge to long-term minimum and maximum demand forecasting.
- **Large Customers Losses** – Large customers, such as mines, can open, or have temporary or permanent shutdowns, which can significantly impact load in PWC's network. Large loads will impact both minimum and maximum demand.

A reasonably likely to occur forecast therefore needs to consider the above evolving drivers in the demand forecasting methodology by explicitly including solar PV, EVs, spot loads and COVID-19 as key inputs.

1.4. *Industry Practice*

Energeia carried out a review of over 53 documents from AEMO and Australian DNSPs on their network forecasting methodologies, which included minimum and maximum demand forecasting. This was completed to ensure that the demand forecasting methodology selected for this project considered best practice and previous regulator feedback. This section details the findings of this review.

1.4.1. AEMO Forecasting Practice

Energeia firstly reviewed AEMO's updated minimum and maximum demand forecasting methodology[15], which used a combination of two models:

1. **Half-Hourly Model** – Simulated future half-hourly demand and the impact of PV, battery storage and EV. A Machine Learning (ML) algorithm was used to select the best fitting regression variables to drive demand. These variables were time-of-day, month, weekend or weekday, public holiday or not, and temperature.
2. **Generalized Extreme Value (GEV) Model** – Estimated the half-hourly intervals in which maximum and minimum demand were expected to occur for the first forecasted year, based on the distribution of extreme operational demand (P10 and P50), excluding large industrial loads. For variables, the GEV

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[11] AEMO, 2022 Integrated System Plan Inputs and Assumptions, 2021

[12] Green Building Council Australia, A Practical Guide to Electrification: For New Buildings, 2022

[13] ABS, Effects of COVID-19 strains on Australian Economy, 2022

[14] AER, State of The Energy Market 2021

[15] AEMO, Electricity Demand Forecasting Methodology Information Paper (2021)

model used month, rooftop PV capacity, non-scheduled PV generation capacity, count of NMIs, dry temperature, and solar irradiance as key inputs.

1.4.2. Industry Forecasting Assessment

Energeia identified industry best practice from a review of Australian DNSP demand forecasts, benchmarking approaches across a number of key forecasting factors including:

- **Target Variables** – Forecasting resolution
- **Methodology** – Forecasting methodology employed
- **Historical Data Processing** – Key data quality processing steps undertaken
- **Input Factors** – Key inputs considered in the methodology
- **Quality Management** – Includes processes to validate outcomes and to estimate error bounds
- **AER Approval** – Indicates the methodology was approved by the AER

The detailed results of our benchmarking are presented in Appendix F – Industry Practice.

Energeia's research found that the industry appears to be moving from a trend-based forecasting approach for connections and demand to a more sophisticated approach using multifactor regression, and more novel techniques, including agent-based simulation. AEMO has updated its demand forecasting methodology to now be based on a combination of a machine learning model for hourly loads and an extreme value model.

Other key trends in demand forecasting include:

- Consideration of electric vehicle, battery and demand management forecasts;
- Spatial forecasts are an emerging trend to improve connection and demand forecast accuracy;
- Minimum demand forecasting; and
- Demand shocks, e.g. COVID.

Energeia considered the above key findings when developing and implementing a best practice, fit-for-purpose regional system min/max demand forecasting methodology for PWC.

1.4.3. AER Assessment of Industry Practice

Energeia reviewed the AER's assessment of industry practices, with the findings summarised in Table 3.

Table 3 – AER Assessment of DNSP Forecast Practices

DNSP	AER Assessment Summary
AusNet	• Forecast likely reasonable had the pandemic not occurred • Accepted forecasts after adjusting first forecast year for COVID-19 impacts
Powercor	• Demand forecast is overstated, as some key variables were not present in their regression model and instead added as post-modelling adjustments • Did not adjust for COVID-19 • AER Adopted AEMO's demand forecast of Powercor's network, based on historically greater accuracy
Energex	• Maximum demand forecasting methodology was reasonable but may be overstated • Unclear on the sufficiency of the chosen summer peak demand sample for robust forecasts • New approach that accounted for energy efficiency and network demand management seemingly failed to account for future impacts of network demand management • Despite some issues, satisfied with overall method and outcomes
Endeavour Energy	• Simple, but reasonable approach to maximum demand forecasting • Limited by only directly modelling weather and calendar effects, without directly modelling some key drivers, including economic growth, population growth, household growth, electricity price, other energy prices, changes in technology and Government policies • Resulting forecasts were reasonable

Essential Energy	• Valid and reasonable overall forecasting approach • Difficult to understand all underlying assumptions of customer number projections but modelling seemingly includes similar demand drivers as AEMO • Winter and summer growth rates are consistent with AEMO and historical trends • Reasonable forecast results
Ergon Energy	• Reasonable overall forecasting approach • Similar, but more limited set of demand drivers compared to AEMO • Trends broadly in line with AEMO's • Could be improved with model and variable specification and adjustments for DER and spot loads post-modelling

Source: Energeia, Various AER and DNSP Sources

Based on our review of the AER's findings and conclusions regarding recent DNSP maximum and minimum demand forecasts and forecasting methodologies, Energeia ensured that the forecasting methodology and inputs reflected methodologies and inputs previously approved by the AER, and avoided issues identified by the AER as potentially leading to unlikely to occur forecasts. This included using multi-factor regression and considering the appropriateness of the following forecast drivers:

- Weather and calendar effects;
- COVID-19 effects;
- economic growth;
- population growth;
- household growth;
- electricity price effects;
- other energy price effects;
- network demand management effects;
- energy efficiency effects;
- changes in technology; and
- Government policies.

Additionally, Energeia considered the key question of the length of historical data used in the forecast, and how consistent the resulting forecast was with historical trends and AEMO's forecast, where available. Energeia also took special care when adding factors as part of post modelling adjustments.

A detailed explanation of our fit-for-purpose, best practice forecasting methodology is presented in Section 3.

2. Scope and Approach

PWC engaged Energeia to develop a new system demand forecasting method that reflects industry best practice and is fit-for-purpose based on PWC's business and regulatory requirements and changing forecasting drivers.

2.1. Scope

Energeia was required to provide an annual forecast of maximum and minimum demand at the system level for each region in PWC's network (Darwin-Katherine, Alice Springs, and Tennant Creek) to feed into PWC's regulatory documentation and inform future network planning, capital expenditure and pricing decisions.

The required forecasts were to provide a 10-year outlook to reach the 2031-32 financial year, from the most recent year of historical Transmission and Distribution Annual Planning Report (TDAPR) data (i.e., the 2021-22 financial year)[16]. Additionally, the forecasts needed to follow the TDAPR style by including P10, P50 and P90 probabilities of exceedance.[17]

In order to ensure forecasts are repeatable and able to withstand regulatory scrutiny, this report also documents the methodology, the key inputs and assumptions used.

2.2. Energeia's Approach

Energeia worked closely with PWC to develop the following scope and approach to meet the project objectives:

1. **Document Requirements** – Energeia reviewed the regulatory framework, recent regulatory determinations and engaged with stakeholders to define the key forecasting requirements
2. **Identify Industry Best Practices –** Energeia benchmarked peer-Distributed Network Service Provider (DNSP) forecasting methodologies from recent regulatory cycles to identify industry best practices.
3. **Develop Forecast Procedure** – Based on the outcomes from steps 1 and 2, Energeia developed a best practice, fit-for-purpose procedure for producing demand forecasts.
4. **Gather Inputs** – Energeia gathered the most recent inputs from PWC, as well as a variety of external inputs from reputable sources, for use in the forecasting methodology optimisation and forecasts.
5. **Forecast Model Optimisation** – Energeia implemented the forecasting procedure to produce forecasts to 2031-32 of maximum and minimum system demand for each region in PWC's network.
6. **Model Validation –** Energeia worked closely with PWC Subject Matter Experts (SMEs) to validate the methodology, inputs, and outputs of the demand forecasting model.
7. **Documentation –** Energeia provided documentation for the produced forecasts, including presentation materials and this report.

[16] Note that forecasts were initially produced with FY21 actuals as the final historical year, but post-model adjusted to the FY22 actuals once they were approved for use. See Section 3.3.4

[17] Probability of exceedances outline the percentage likelihood that demand will exceed the forecast due to temperature variances. See Appendix C – Weather Normalisation

3. Methodology

This section describes the forecasting methodology Energeia used to develop the minimum and maximum demand forecasts for all three PWC networks (Darwin-Katherine, Alice Spring and Tennant Creek), which can be summarised into the following key stages:

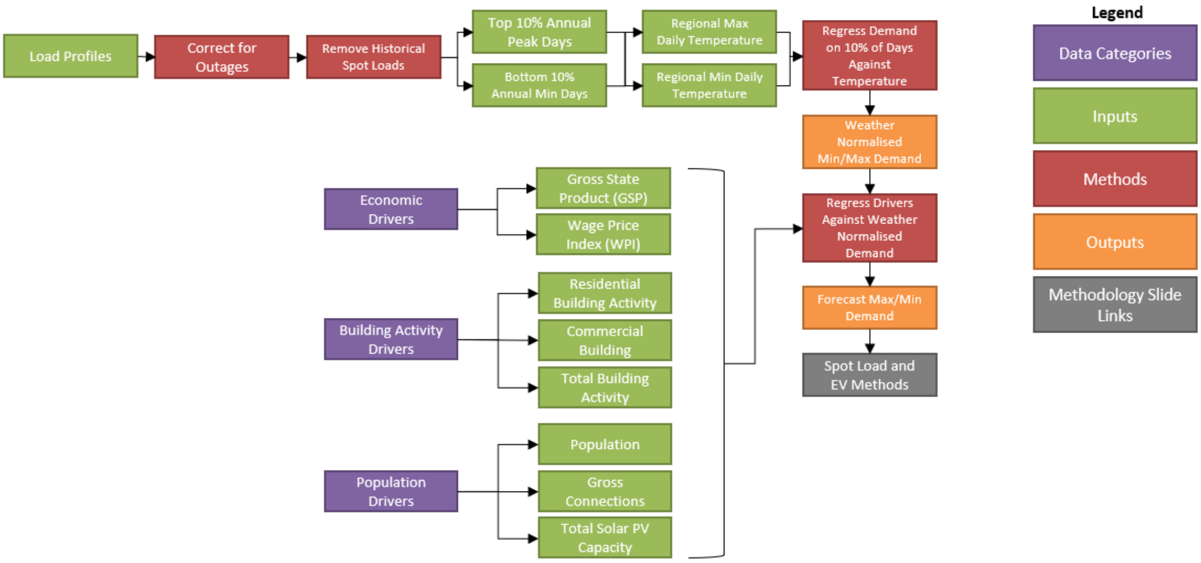
1. **Develop Demand Forecasting Procedure** - Energeia developed a fit-for-purpose demand forecasting procedure that satisfied the key requirements and reflected industry best practice
2. **Data Gathering and Processing** – Energeia processed load profiles provided by PWC for outages, historical spot loads and weather normalisation.
3. **Forecast Model Optimisation –** Energeia identified the optimal model parameters given fitness, sign and p-value, then post-processed spot and EV loads and adjusted to FY22 actuals.
4. **Validate Optimised Results** – Energeia reviewed the technically optimised forecasts against historical trends and validated them with comparisons to published forecasts[18] and sharing with PWC stakeholders prior to finalisation.

Each stage of the methodology is further explained below.

3.1. Develop Demand Forecasting Procedure

Energeia's demand forecasting procedure is informed by the in-depth research and industry benchmarking of PWC's peer DNSPs[19]. The updated demand forecasting procedure developed for PWC has been aligned with industry best practices, with consideration of the data available. Figure 1 shows the weather normalisation and regression methodologies, and Figure 2 outlines the treatment of Spot Loads and EVs.

Figure 1 – Weather Normalisation and Regression Methodology Overview

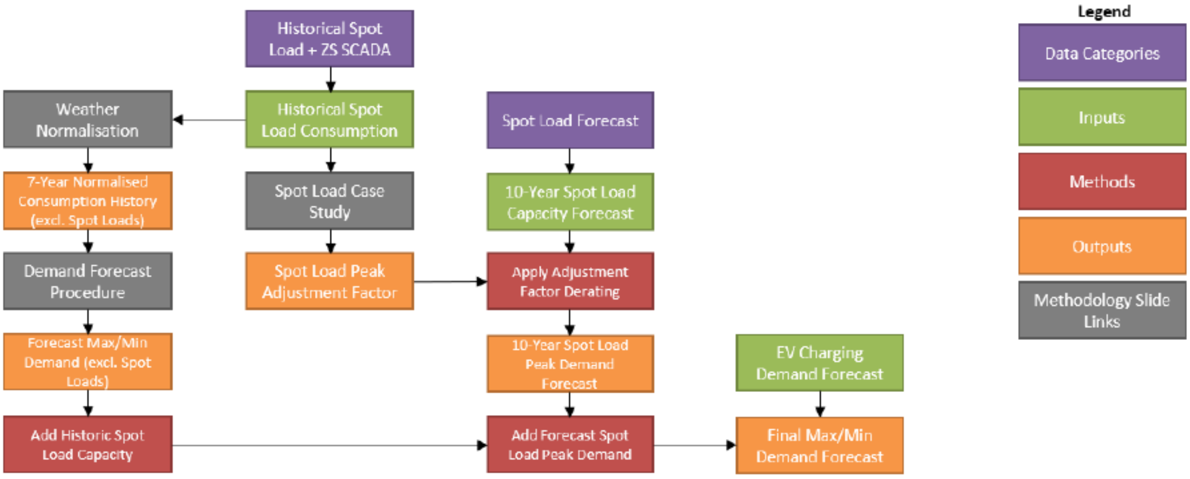


Source: Energeia

[18] AEMO for NT Utilities Commission, 2022 Northern Territory Electricity Outlook Report Data

[19] See Appendix F – Industry Practice for a detailed summary of the findings

Figure 2 – Spot Loads and EV Methodology Overview



Source: Energeia

This procedure, and in particular the key methods, are further explained below.

3.2. *Data Gathering and Processing*

Data gathering and processing of the inputs supplied by PWC was undertaken to ensure that inputs utilised were representative of underlying demand trends. Processing undertaking in this step included outage correction, treatment of spot loads and weather normalisation. Table 4Table 4 details the key PWC-provided data sources used in the implemented minimum and maximum demand forecasting methodology.

Table 4 – Data Sources

Data Type	Data Description	Start/End Date	Contact Provided
Historical Temperature	Daily Max and Min temperature by network	July 2014 – June 2021	Goutham Maddirala
Historical Half-Hourly Network Demand	Half-hourly demand trace by network	July 2014 – June 2021	Santos Sukumaran
Outage Record	Date and time of generator and network outages	January 2015 – May 2021	Santos Sukumaran
Half-Hourly Zone Substation Demand*	Half-hourly zone demand trace by zone substation	April 2016 – March 2021	Santos Sukumaran
Historical Spot Loads	Half-hourly meter data for major historical spot loads	April 2013 – October 2021	Santos Sukumaran
Spot Load Forecast	Annual spot load additions by region	2023 – 2032	Santos Sukumaran

Source: Energeia, PWC
*Note: Only four sample subdivisions considered in spot load case study

3.2.1. Outage Correction

Energeia corrected for outages in the historical interval data provided by PWC, as it otherwise distorts historical minimum demand trends.

Appendix A – Outage Correction covers the method used for interpolating outage impacted data.

3.2.2. Spot Load Correction

Energeia removed historical spot loads from historical (outage corrected) interval data using recorded temperature data supplied by PWC. The remaining historical load time series were then carried forward into the weather normalisation step.

Spot loads are typically treated separately from the rest of the minimum and maximum demand forecast due to differences in the level of specific knowledge regarding their future timing and impact compared to other growth-related factors. This approach is also consistent with industry best practice.[20]

3.2.3. Weather Normalisation

Energeia weather normalised historical half hourly network load data in order to produce 3 levels of probability of exceedance (POE or P): P10, P50 and P90 which indicate the temperature assumed during the forecast minimum and maximum demand. This temperature is calculated to ensure the percent of intervals which are expected to exceed this normalised temperature value are 10%, 50% and 90% respectively.

The process Energeia used to weather normalise operational demand is described in detail in Appendix C – Weather Normalisation.

3.3. Forecast Model Optimisation

The resulting outage, spot load and weather corrected minimum and maximum demands for each historical year were then used in a multi-factor regression model optimisation procedure to identify the optimal parameters and data history to reasonably and accurately forecast network minimum and maximum demand over the forecast period.

3.3.1. Regression Overview

All possible regression drivers identified by Energeia's best practice review and desktop research were considered as potential independent variables into the multi-factor maximum and minimum demand forecasting models, as outlined in detail below. Each variable was assessed to determine regression statistics and the most statistically significant regression equation with the correct signs and lowest p-values.

External forecasts of the statistically significant independent variables with the correct sign were used as potential inputs into the regression equations to forecast the maximum and minimum demand for the corresponding hour and region.

Both 5- and 7-year regressions were considered, with up to two independent variables. In addition to these regressions, simple linear trends (5- and 7-year) were considered to cover instances where regression results were statistically insignificant or deemed unsuitable based on trend analysis.

3.3.2. Data History Length

The load profiles and historic spot load additions and subtractions provided had 7 years of complete history, and hence 7-year regressions and trends were produced to include these histories in their entirety. 5-year regressions and trends were also produced to provide a greater focus on the most recent years of historical data, whilst still maintaining a sufficient number of data points for a reasonable regression.

3.3.3. Number of Independent Variables

There were 9 total potential independent variables considered to drive regressions, with up to two variables per regression model. Energeia chose to test no more than two independent variables to avoid overfitting, based on experience developing system minimum and maximum demand forecasts for other DNSPs and TNSPs.

3.3.4. Types of Independent Variables (Drivers)

Table 5 lists the independent variables tested in the regression analyses by category and their definitions. Energeia used a variety of categories to cover a reasonably broad range of potential minimum and maximum demand drivers, without biasing a particular category, e.g., having only economic indicators drive the regression.

[20] See Appendix F – Industry Practice

Table 5 – Regression Independent Variables, Categories and Definitions

Category	Independent Variable	Definition
Population	Population	Total number of people in the NT
Economic	Gross State Product (GSP)	Monetary metric of the total value added across all industries in the NT
	Wage Price Index (WPI)	Measure of the price of labour in the NT, unaffected by changes in labour force, hours worked or employee characteristics
Building	Cumulative Residential Building Activity	Monetary measure of the total value of residential building work done in the NT
	Cumulative Commercial Building Activity	Monetary measure of the total value of commercial building work done in the NT
	Total Cumulative Building Activity	Monetary measure of the total value of building work done in the NT
Connections	Total Gross Residential Connections	The total sum of existing and new* residential connections (HV and LV) in PWCs network area in the NT
	Total Gross Commercial Connections	The total sum of existing and new* commercial connections (HV and LV) in PWCs network area in the NT
Solar PV	Total PV Capacity	The total rated capacity of behind-the-meter solar PV in the NT

Source: Energeia
*Note: 'Existing' and 'new' connections refer to the volumes described with these names in PWC's Category Analysis RIN Response

3.4. Annual Minimum and Maximum Demand Forecast Model

With forecasts of maximum and minimum demand by hour, the maximum or minimum demand for the forecast years were determined for each region (i.e., the maximum or minimum was selected for each year based on the highest or lowest annual hourly loads). Regressions were completed by hour to account for maximum or minimum demand shifting to a different hour of the day, which may be driven by different independent variables.

3.4.1. Selection of Annual Demand Forecast

Six potential forecasts for each region and each demand type (maximum or minimum) are an outcome of the methodology outlined in the above sections:

- 5-Year History, Single Variable Regression
- 5-Year History, Two Variable Regression
- 5-Year History, Trended
- 7-Year History, Single Variable Regression
- 7-Year, Two Variable Regression
- 7-Year, Trended

Regression forecasts were the selected over trend forecasts, however, trends were used if the regression models were deemed insufficient, which occurred when:

- P-values were above >0.05, which is considered statistically insignificant
- R^2 was too low (<0.65)
- Beta-coefficients were considered unfit to forecast. This occurred when an inverse to the expected relationship was found, e.g., it is unreasonable to have increasing population drive decreasing demand.
- Forecasts did not pass a sense check. Where the forecast produced unreasonable results, which was validated with PWC stakeholders, it was not selected.

Once a forecast was selected, the final steps were to add forecast spot loads and EV charging loads to it, as outlined below.

3.4.2. Spot Load Forecasts

PWC provided a forecast of yearly additional spot load capacities added to each network region by year. To determine how much load these spot loads were expected to add to the forecast minimum and maximum demand, Energeia performed a case study on historical spot load additions on select PWC zone substations. Appendix B – Spot Load Case Study, covers this in detail.

The outcome of the study were two adjustment factors (one for maximum demand, one for minimum demand) that were multiplied by PWC's spot load capacity forecast to estimate additions to the selected minimum and maximum demand forecasts.

3.4.3. EV Forecasts

Forecast EV charging demand was added to produce the final minimum and maximum demand forecasts. As no EV forecasts for the NT are available in the public domain, these forecasts came from Energeia's 2020 EV uptake forecasts for the Department of Industry, Science, Energy and Resources.[21]

3.4.4. Post-Model Adjustment to FY22 Actuals

An important note is that, at the time the regressions were produced, FY21 actuals were the most recent historical data-point that could be used to produce forecasts. However, FY22 actuals were approved for use during production of these forecasts.

A post-model adjustment was made to account for these FY22 actuals to prevent any sudden "jumps" up or down between the final year of historical data and the first year of forecasts. This was done by shifting the forecast to align with FY22 actuals (i.e., without rerunning regressions), with FY23 being the first year of forecast.

A complete refresh of forecasts using FY22 actuals, including rerunning the regression methodology presented here, will be completed after submission of the Initial Regulatory Proposal.

3.5. Validate Optimised Results

Energeia engaged PWC stakeholders throughout the forecasting process to provide an opportunity for feedback on the validity of the recommended system demand forecasts. Additionally, solar PV uptake – as a key driver of demand reduction – was compared to NT Outlook Report for the Utilities Commission – see Section 4.1.5.

Upon carrying out the described methodology, the minimum demand forecast for Tennant Creek did not pass subject matter expert validation with PWC stakeholders. As a result, the methodology was rerun with updated input datapoints (incl. FY22) included as part of the regressions and trends produced.

[21] Energeia recommends that for future iterations, PWC commissions an updated EV charging demand forecast.

4. Key Inputs

This section covers the key inputs used as independent variables in the multi-factor regression forecast of minimum and maximum demand. All inputs were validated with key PWC stakeholders prior to finalisation.

4.1. Regression Drivers

Table 6 shows a summary of all the potential minimum and maximum demand drivers, including their source, how they are forecasted and the years of history and forecast available.

Table 6 – Summary of Potential Minimum and Maximum Demand Drivers

Driver	Source	Forecasting Summary	Years of History	Years of Forecast
Population (#)	ABS (undated) https://dbr.abs.gov.au/ (historical) NT Treasury (2019) https://treasury.nt.gov.au/dtf/economic-group/population-projections (forecast)	Applying population growth rates based on NT Treasury projections	40+	25
Cumulative Residential Building Activity ($)	ACIF (2019) https://www.acif.com.au/documents/item/869	Applying growth rates based on ACIF NT building activity forecasts to 2028, with trend to 2030	40+	7
Cumulative Commercial Building Activity ($)	ACIF (2019) https://www.acif.com.au/documents/item/869	Applying growth rates based on ACIF NT building activity forecasts to 2028, with trend to 2030	40+	7
Total Cumulative Building Activity ($)	ACIF (2019) https://www.acif.com.au/documents/item/869	Sum of residential and commercial	40+	7
Gross State Product ($)	RDA Northern Territory (2020) https://economy.id.com.au/rda-northern-territory/gross-product?WebID=150 (historical) BIS Oxford Economics (2020) https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/bis-oxford-economics-macroeconomic-projections.pdf?la=en (forecast)	Applying annual GSP growth rate forecasts projected by BISOE	30+	30
Wage Price Index	ABS, Department of Treasury and Finance (undated) https://e.infogram.com/f136daf4-d710-4c22-b722-22e650873e02?src=embed	Using source for historic and forecast to 2025, applying a trend to 2030	10	4
Total Gross Residential Connections	PWC RIN responses: https://www.aer.gov.au/networks-pipelines/performance-reporting/power-and-water-corporation-rin-responses + Energeia Connections Forecast Model	Using best performing regression using population/economic variables	4	10
Total Gross Commercial Connections	PWC RIN responses: https://www.aer.gov.au/networks-pipelines/performance-reporting/power-and-water-corporation-rin-responses + Energeia Connections Forecast Model	Using best performing regression using population/economic variables	4	10
Total PV Capacity	AEMO Behind the Meter PV Data + PWC RIN: https://www.aer.gov.au/networks-pipelines/performance-reporting/power-and-water-corporation-rin-responses + Energeia PV Uptake Model	Using a regression of return-on-investment against actual PV uptake	9	10

Source: Energeia

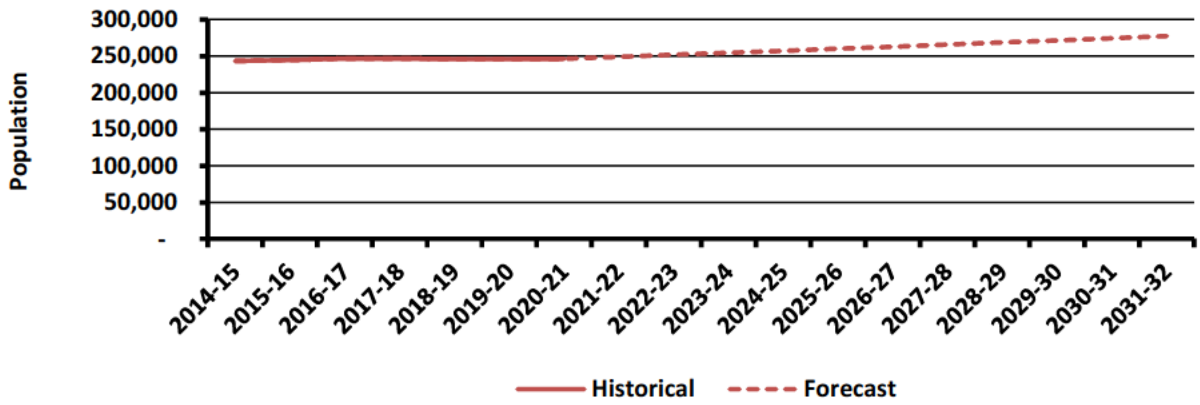
Energeia also provided a critical analysis of the GSP and population forecasts used, in Appendix D – Government Forecast Analysis, to test their level of potential bias in order to ensure they supported realistic minimum and maximum demand forecasts.

4.1.1. Population

Population growth tends to have a strong relationship with demand growth, particularly residential loads.

Figure 3 displays the historical and forecast total population for the NT. Population rose steadily in the past, peaking in 2017-18 and plateauing since. In contrast, the NT Government predicts a strong growth in population in their forecasts.

Figure 3 – NT Historical and Forecast Total Population



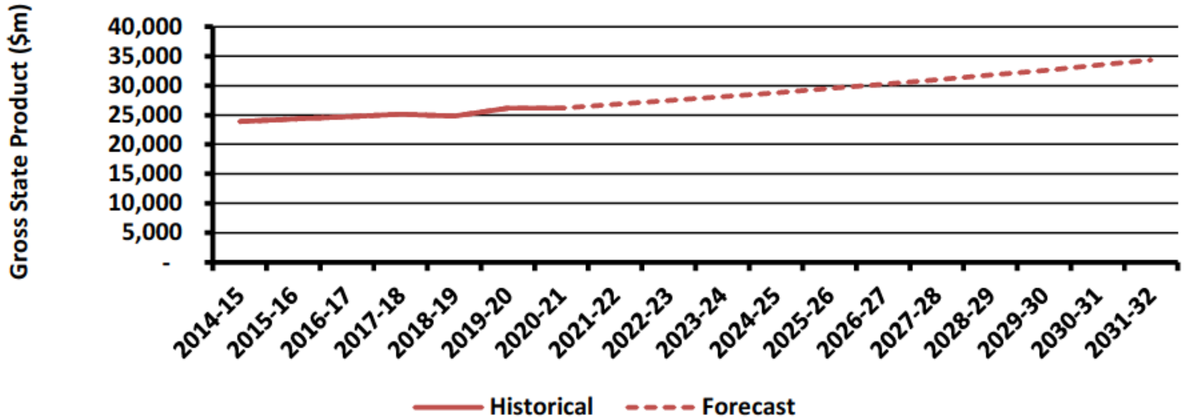
Source: Energeia Analysis, Northern Territory Government (2019)

4.1.2. Economic

GSP indicates growth in business activity, which is also correlated with an increase in demand.

Figure 4 displays the historical and forecast GSP for the NT. Historical GSP has risen steadily, though it has plateaued during the COVID years. The BIS Oxford Economics (BISOE) forecast predicts a continuation of this trend.

Figure 4 – NT Historical and Forecast Gross State Product

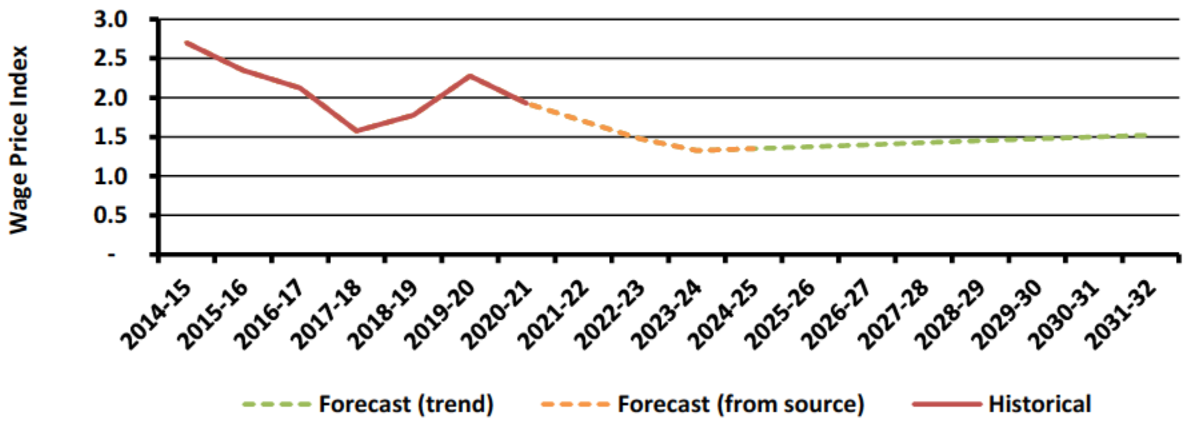


Source: ABS (2021), BIS Oxford Economics (2020)

The WPI indicates consumer buying power, including shifts in energy usage due to purchase of new technology including PV, batteries and/or EVs.

Figure 5 displays historical and forecast WPI for the NT. WPI fell historically, reaching a low point in 2017-18. It then rose to a peak in 2019-20 but fell again after during the beginning of the pandemic years. The forecast from the ABS predicts this recent fall to continue until 2024-25, before recovering. Energeia has trended this rise to continue out to 2031-32, due to the lack of a publicly available forecast.

Figure 5 – NT Historical and Forecast Wage Price Index



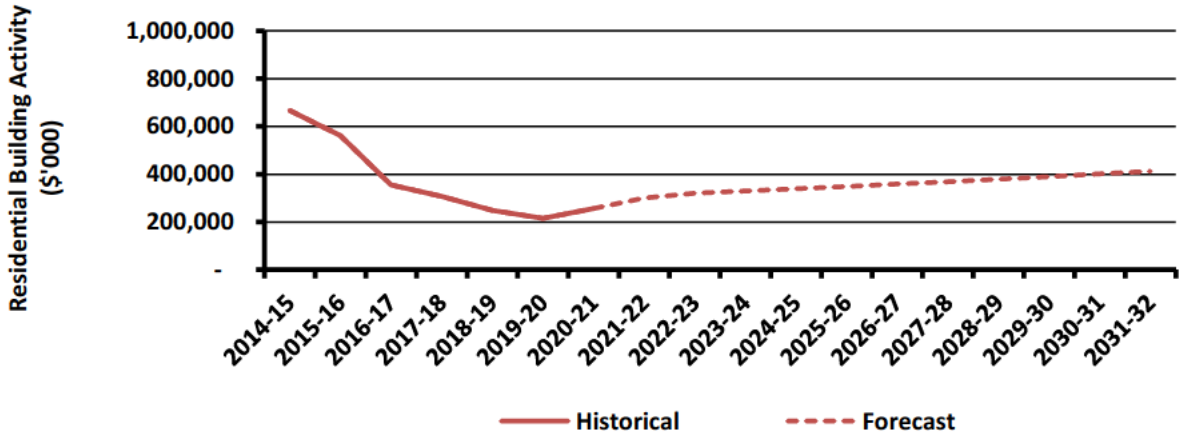
Source: ABS (2021), Energeia Analysis

4.1.3. Building

Figure 6 and Figure 7 display the historical and forecast building activity, segmented by residential and commercial building activity, respectively.

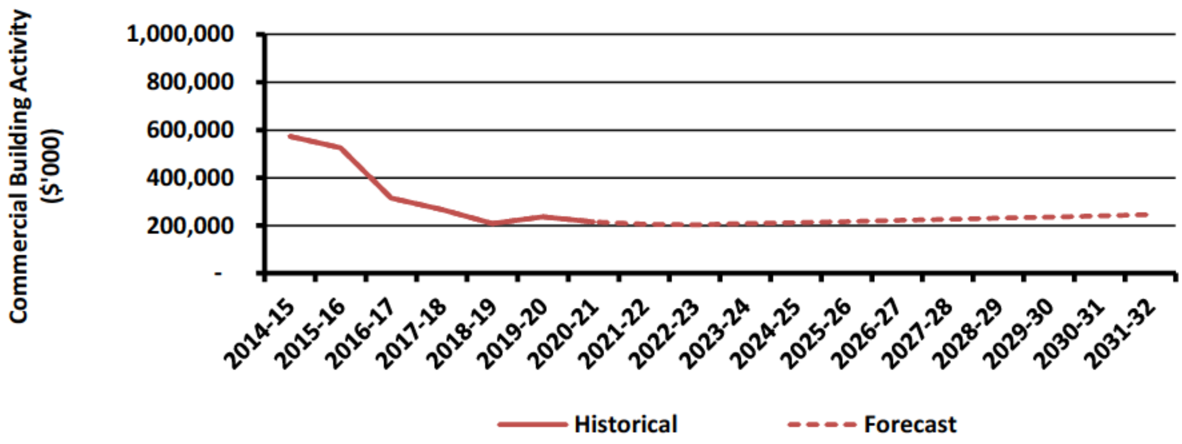
Both historical residential and commercial building peaked at the start of the period and fell thereafter, plateauing in recent years, with residential building activity rising again. The ACIF forecast predicts a steady growth in residential building activity, with some continued plateauing and later slight growth in commercial building activity.

Figure 6 – NT Historical and Forecast Residential Building Activity



Source: ACIF (2019), Energeia Analysis

Figure 7 – NT Historical and Forecast Commercial Building Activity



Source: ACIF (2019), Energeia Analysis

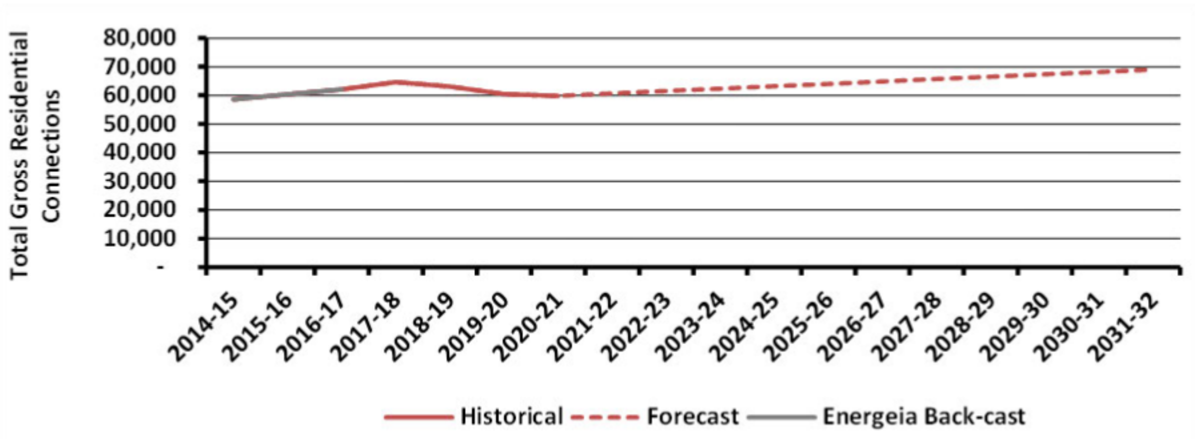
4.1.4. Connections

Growing residential and commercials connections is a direct indication of increased load in the network, which in turn drive minimum or maximum demand.

Figure 8 and Figure 9 display the back-cast, historical and forecast gross connections, segmented by residential and commercial building activity, respectively. Residential gross connections rose and then fell historically and are forecast to grow steadily. Commercial gross connections fell and plateaued historically and are also forecast to rise steadily.

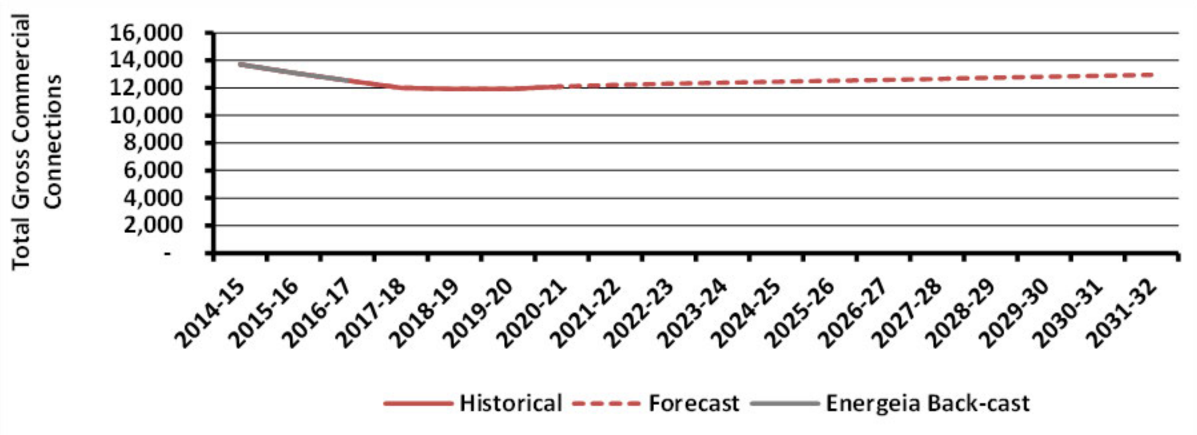
Energeia produced the reporting below as part of the RIN connection forecasting workstream for PWC – which is described in its own detailed report. The back-cast history was used to extend the limited data history (only 4 years of historical actuals) and was based on the relationship between historical gross connections and customer numbers.

Figure 8 – NT Back-Cast, Historical and Forecast Total Gross Residential Connections



Source: PWC Category Analysis RIN Response, Energeia Analysis

Figure 9 – NT Back-Cast, Historical and Forecast Total Gross Commercial Connections



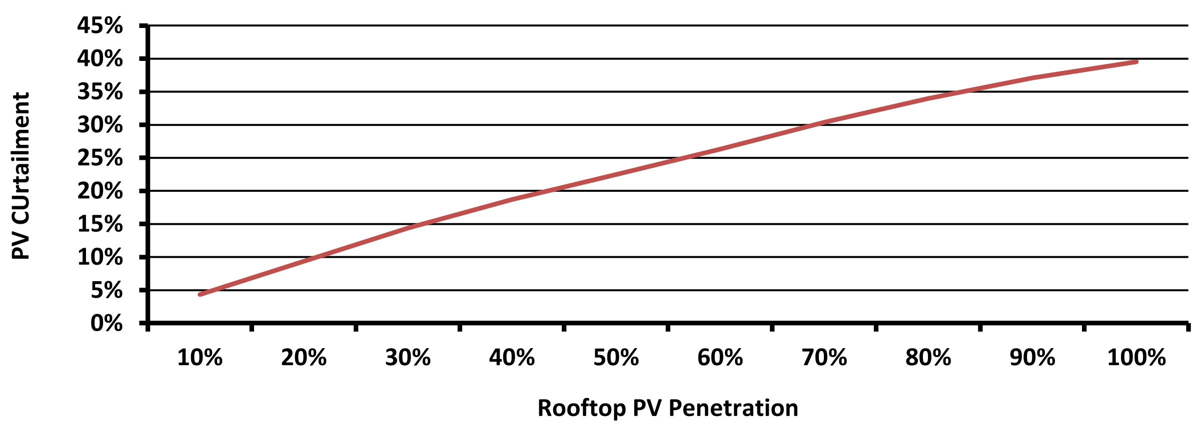
Source: PWC Category Analysis RIN Response, Energeia Analysis

4.1.5. Solar PV

Energeia used its PV uptake model to forecast cumulative installed distributed PV capacities in the NT. The model considers financial drivers of PV uptake for consumers. First-year return-on-investment (ROI) is used as the primary driver in a regression based forecast of customer uptake of PV.

Curtailment reduces the level of PV capacity exporting during times of minimum demand, alleviating some stress on the network caused by low demand. For minimum demand forecasts, PV curtailment was estimated based on recent Australian studies which considered the average level of curtailment of solar PV as market penetration increases. The estimated level of curtailment expected at various levels of PV penetration is shown in Figure 10.

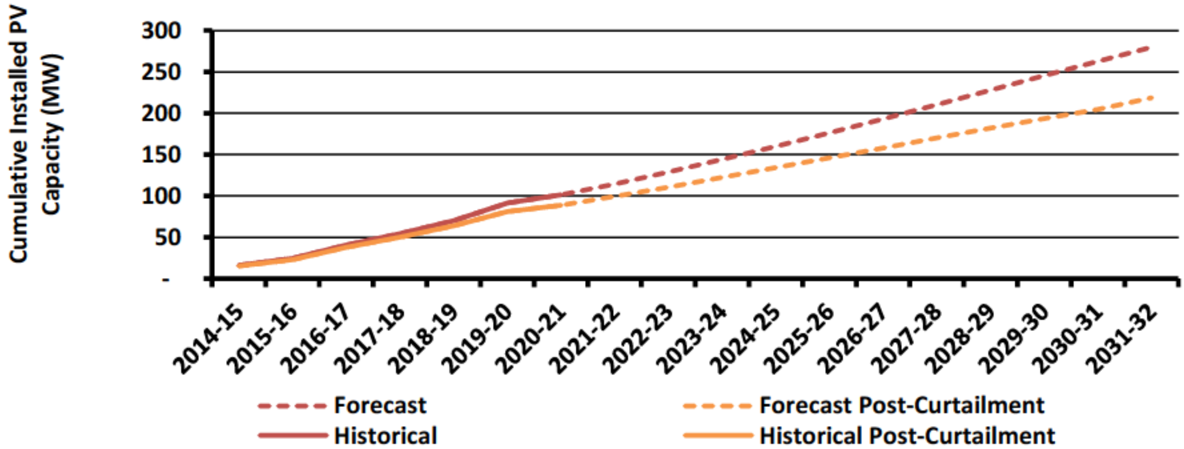
Figure 10 – Curtailment Estimates



Source: Energeia, L. Ochoa and A. Procopiou, (2019), Increasing PV Hosting Capacity: Smart Inverters and Storage, Webinar

Figure 11 displays the historical and forecast PV capacities, both pre- and post-curtailment. Historical capacity grew rapidly, and forecasts are expected to see continue growth. Continuing growth in solar PV uptake will likely continue to be a key driver in reducing maximum and minimum demands occurring during solar hours.

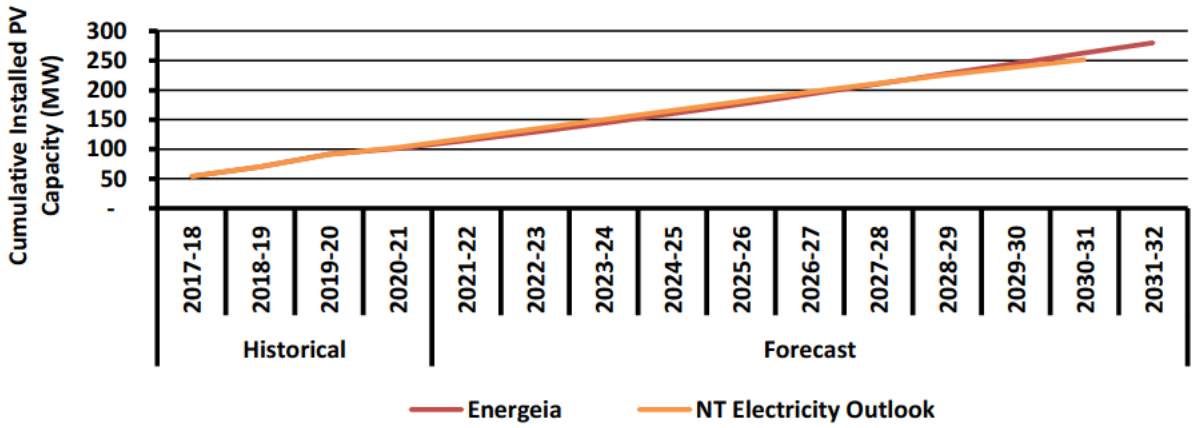
Figure 11 – NT Historical and Forecast Cumulative Distributed PV Capacity, Pre and Post-Curtailment



Source: Energeia Analysis, L. Ochoa and A. Procopiou (2019)
Note: Post-curtailment capacity is the effective maximum allowable solar export during times of minimum demand

Figure 12 displays a comparison of Energeia's forecast with that of the Utilities Commission and shows that both forecasts were very similar in the first five forecast years but diverge slightly in the latest years, with increasing ROI driving Energeia's persistent uptake. This comparison provides evidence for the reasonableness of Energeia's PV uptake forecast.

Figure 12 – Historical and Forecast Cumulative Installed Distributed PV Capacity, Comparison of Energeia and NT Electricity Outlook Report Data

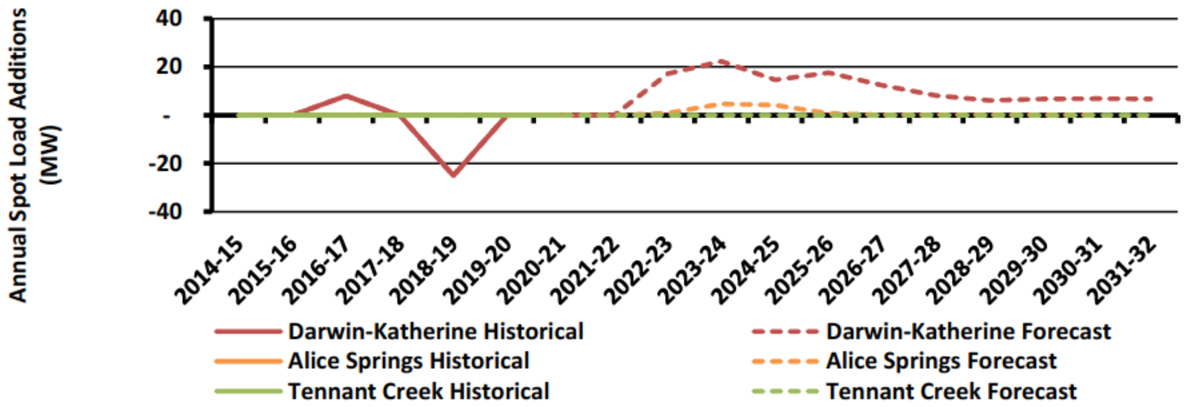


Source: Energeia, NT Utilities Commission (2022)

4.2. Spot Loads (Major and Minor)

Figure 13 displays the historical and forecast annual spot load additions and removals from PWC-provided data. As shown, some spot loads were connected in 2016-17 and some were disconnected in 2018-19 in Darwin-Katherine. The forecast predicts a large amount of spot load capacity connecting annually in the near future, slowing down in later years. Darwin-Katherine notably dominates in spot load additions.

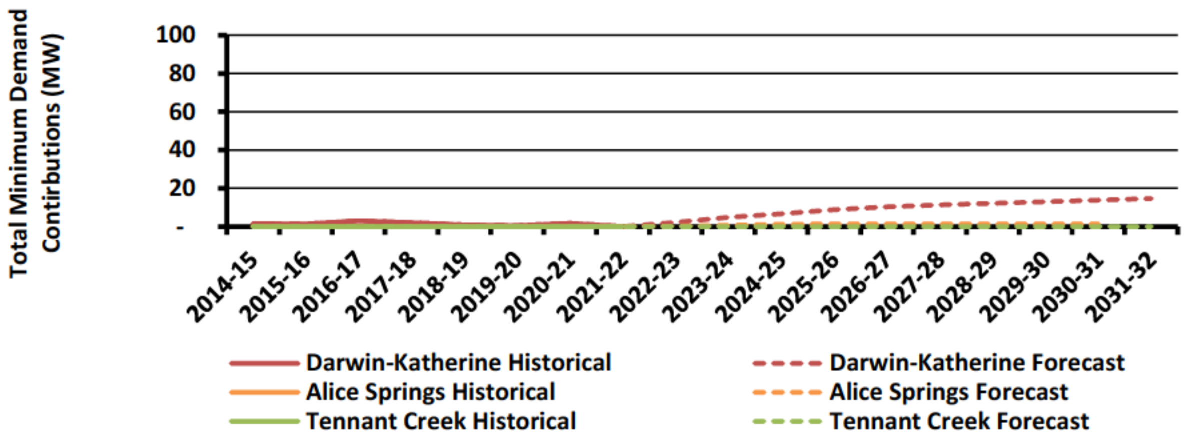
Figure 13 – NT Historical and Forecast Annual Spot Load Additions, by Region



Source: PWC

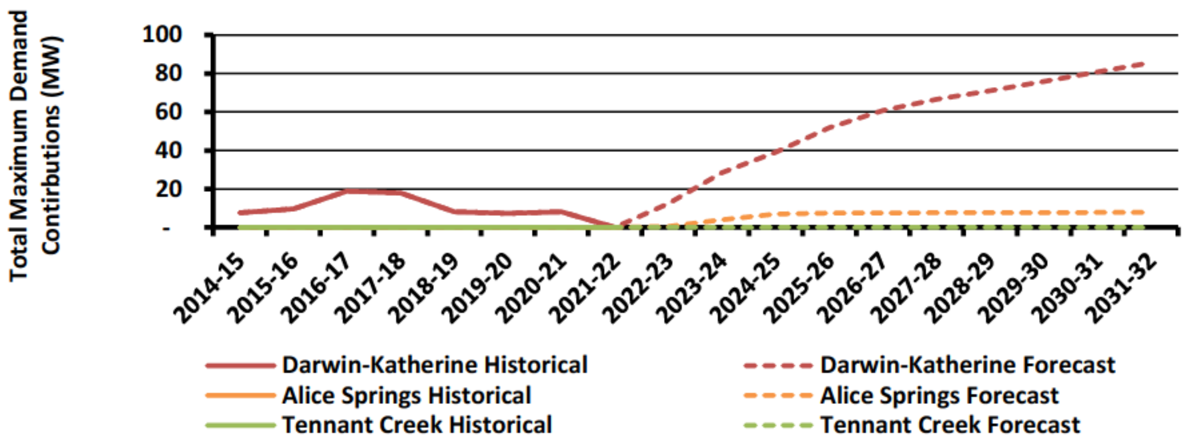
Figure 14 and Figure 15 show the respective minimum and maximum demand contributions from spot loads, both historical and forecast. As discussed in Section 3.2.2, the forecasts were derived based on multiplying the cumulative spot load additions by adjustment factors determined in the spot load case study, discussed in Appendix B – Spot Load Case Study.

Figure 14 – NT Historical and Forecast Spot Load Contributions to Minimum Demand by Region



Source: PWC, Energeia Analysis

Figure 15 – NT Historical and Forecast Spot Load Contributions to Maximum Demand by Region

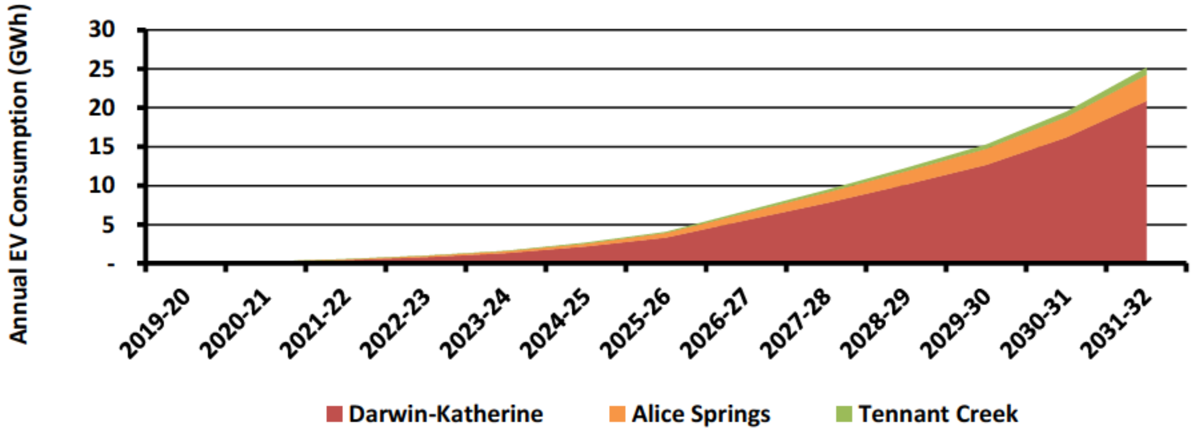


Source: PWC, Energeia Analysis

4.3. *Electric Vehicles*

Figure 16 shows the historical and forecast annual EV charging consumption in the NT. Note that EV charging loads before 2019-20 were negligible. Energeia forecasts annual charging consumption to reach 25 GWh by 2031-32.

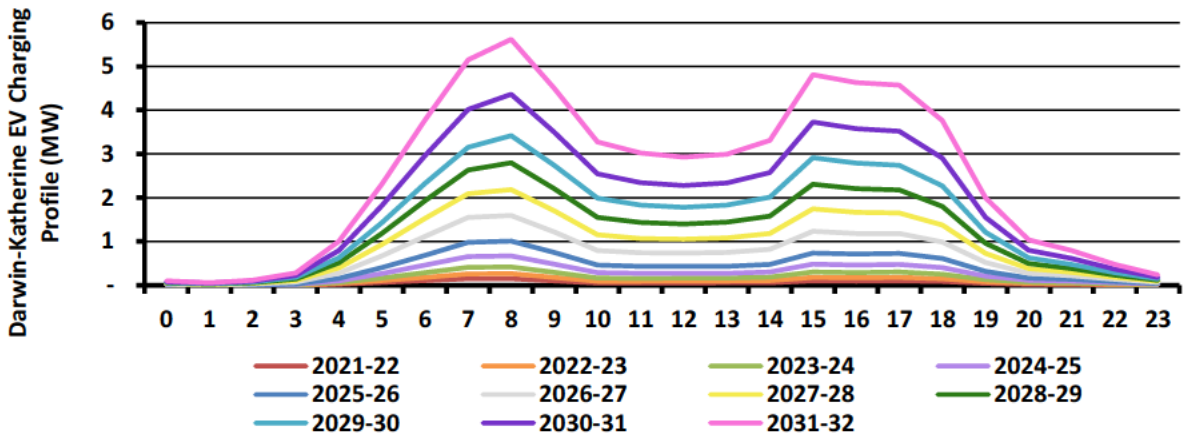
Figure 16 – NT Historical and Forecast Annual EV Charging Consumption



Source: Energeia

Figure 17 displays Energeia's forecast average annual hourly charging load profiles for Darwin by year. Peak and minimum day charging profiles were not available, however, they are not expected to have a material impact on the maximum or minimum daily results at this stage.

Figure 17 – Darwin-Katherine Average Daily EV Charging Profile, by Forecast Year



Source: Energeia

Although not shown here, EV charging in the other NT regions were included in the final forecasts.

5. Forecasting Results

This section reports the results of Energeia's forecast of minimum and maximum demand by region and POE, including the impact of spot loads and EVs, and how the forecasts compare to AEMO's demand forecasts.[22]

Table 7 summarises the final forecast methods Energeia selected by region. More detailed results on regression parameterisation and output ranges are shown in Appendix E – Detailed Results.

Table 7 – Recommended Forecast Method Summary by Region

Region	Min/Max Demand	Years of History	Trend or Regression	One or Two Variable Regression	Regression Variables at Min/Max Hour(s)	Hour(s) of Max/Min
Darwin-Katherine	Minimum	7	Regression	One	PV Capacity	3pm, 1pm
	Maximum	5	Regression	One	PV Capacity, Commercial Connections	4pm, 7pm
Alice Springs	Minimum	5	Trend	-	-	1pm
	Maximum	7	Regression	One	Commercial Connections	5pm, 6pm
Tennant Creek	Minimum	7	Trend	-	-	1am, 2am, 2pm
	Maximum	7	Trend	-	-	5pm

Source: Energeia

Interestingly, the forecasts for Darwin-Katherine are driven by PV capacity, while the forecasts for the other, smaller regions are mainly trended.

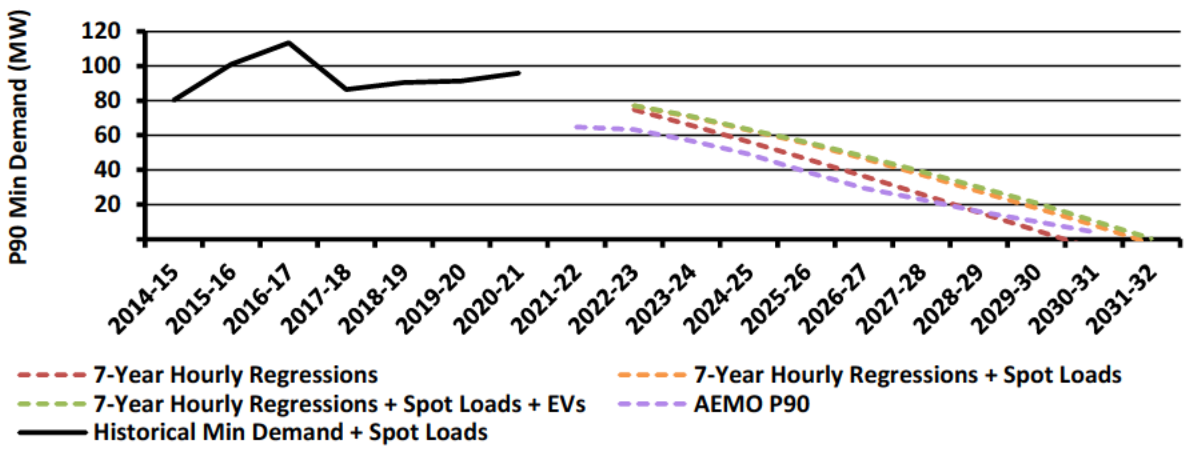
5.1. *Minimum Demand*

5.1.1. Darwin-Katherine

For Darwin-Katherine, Energeia selected the 7-year, single variable regression for the minimum demand forecast. The forecast minimums occur at 3pm initially and 1pm in later years, in contrast to historical minimums which primarily occurred at 4am. This shift is driven by PV capacity in the regression model.

Figure 18 displays the P90 minimum demand forecast and indicate how spot load and EVs impact demand trends. Figure 19 indicates the final P10, P50 and P90 minimum demand forecasts.

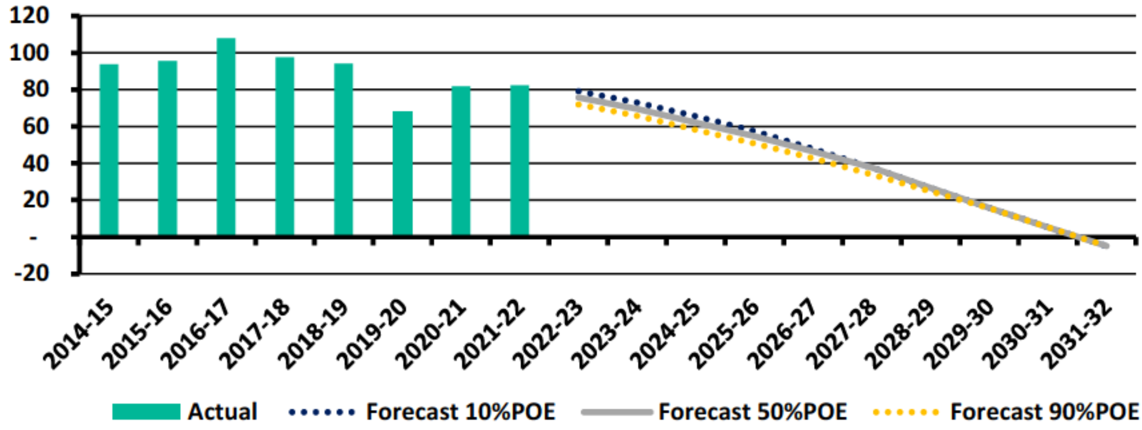
Figure 18 – Darwin-Katherine, Historical and Forecast P90 Minimum Demand, Spot Loads and EVs



Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)
Note that historical demand is weather normalised, and outage corrected, not observed actual demand

[22] AEMO for NT Utilities Commission, 2022, Northern Territory Electricity Outlook Report Data

Figure 19 – Darwin-Katherine, Historical and Forecast P10, P50 and P90 Minimum Demand



Source: Energeia Analysis, PWC

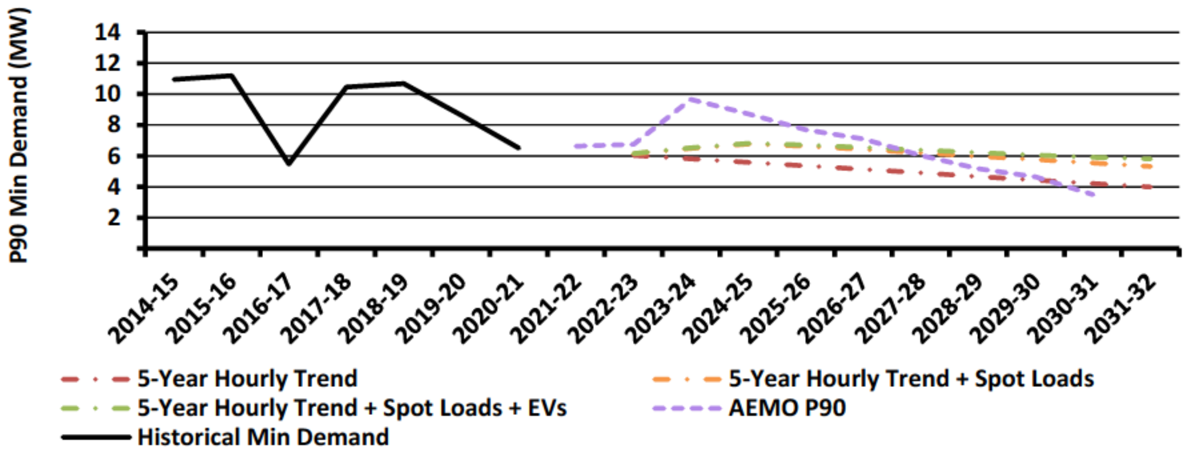
Energeia forecasts minimum demand will fall strongly in future, following increasing PV investment. Forecast spot loads and EVs dampened this decrease. Minimums are expected to reach the negatives by 2031-32.

5.1.2. Alice Springs

Energeia selected the 5-year trend for the Alice Springs minimum demand forecast. The forecast minimums occur at 1pm, where it has also occurred in the past.

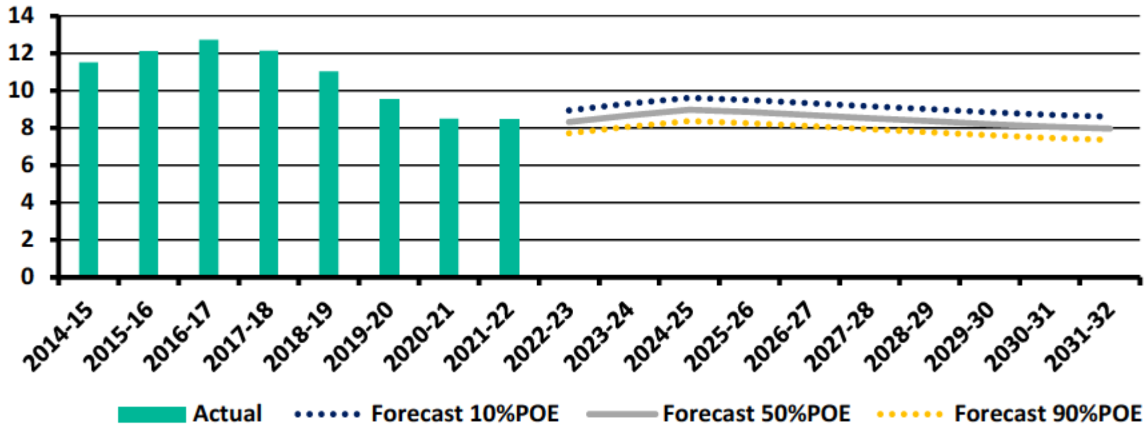
Figure 20 displays the P90 minimum demand forecast and how spot load and EVs impact results. Figure 21 shows the final P10, P50 and P90 minimum demand forecasts.

Figure 20 – Alice Springs, Historical and Forecast P90 Minimum Demand, Spot Loads and EVs



Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)
Note that historical demand is weather normalised, and outage corrected, not observed actual demand

Figure 21 – Alice Springs, Historical and Forecast P10, P50 and P90 Minimum Demand



Source: Energeia Analysis, PWC

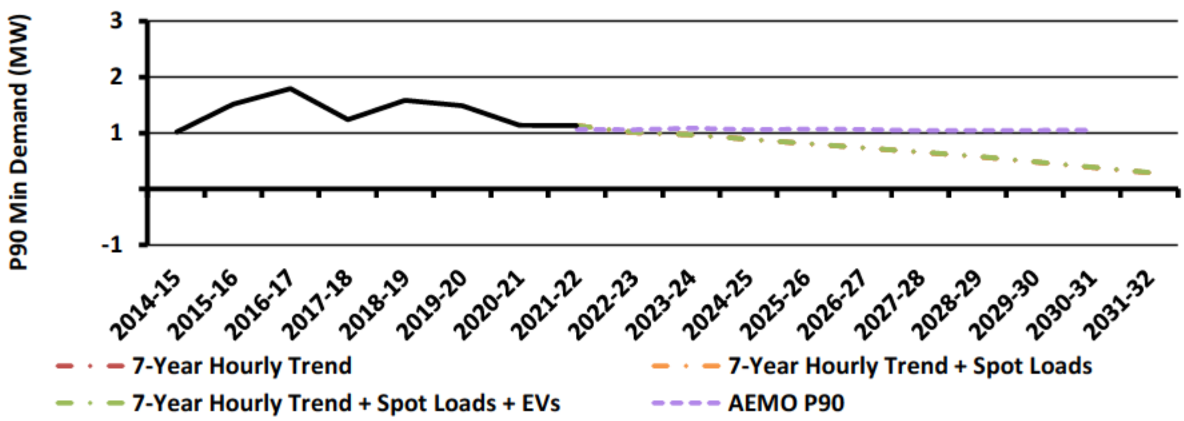
Energeia forecasts minimum demand in Alice Springs to rise initially, due to the [redacted] spot load addition, and then gradually fall to levels similar to the most recent years of history by 2031-32.

5.1.3. Tennant Creek

For Tennant Creek, Energeia selected the 7-year, trend for the minimum demand forecast – after the methodology was rerun.[23] The forecast minimums occur at 2pm for the first forecast year, shifting to 1-2am afterward. Historically, the minimum demand occurrences jumped between 1pm and 12-2am.

Figure 22 displays the P90 minimum demand forecast and how spot load and EVs impact results. Figure 23 shows the final P10, P50 and P90 minimum demand forecasts.

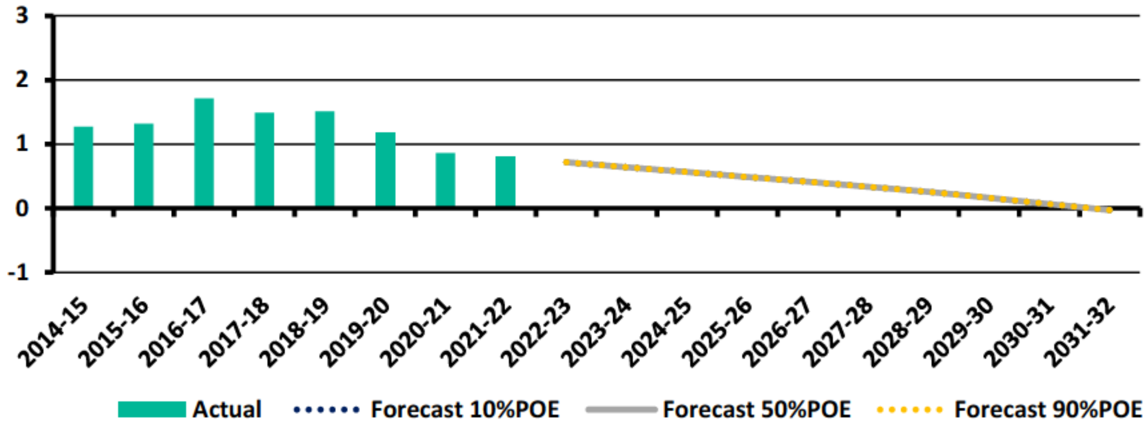
Figure 22 – Tennant Creek, Historical and Forecast P90 Minimum Demand, Spot Loads and EVs



Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)
Note that historical demand is weather normalised, and outage corrected, not observed actual demand

[23] See Section 3.5

Figure 23 – Tennant Creek, Historical and Forecast P10, P50 and P90 Minimum Demand



Source: Energeia Analysis, PWC

Energeia forecasts minimum demand to steadily decrease. There are no forecast spot load additions in Tennant Creek and EV charging loads are expected to have a minimal impact on overall trends. Minimum demand is expected to cross into the negatives by 2031-32.

It is worth noting that Energeia's forecasts of minimum demand deviate significantly from AEMO's P90 forecast.

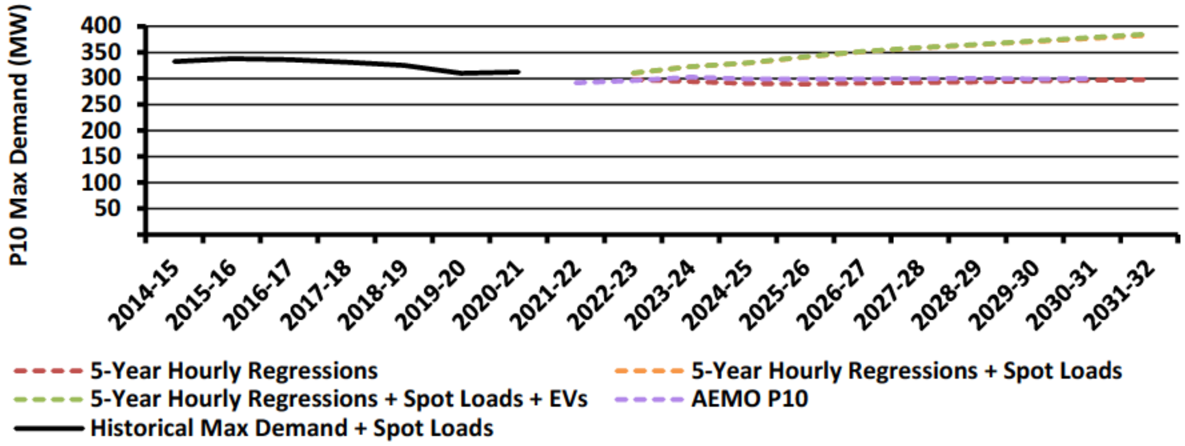
5.2. Maximum Demand

5.2.1. Darwin-Katherine

Energeia selected the 5-year, single variable regression for the maximum demand forecast for the Darwin-Katherine network. Maximums are forecast to occur at 4pm initially, driven by increasing solar PV. In later forecast years this changes to 7pm driven by increased commercial connection volumes. Historical maximums exclusively occurred at 4pm. The forecast change is caused by PV capacity reducing maximum demand during sunlight hours, meaning maximum demands will instead occur at later hours of the evening peak demand period.

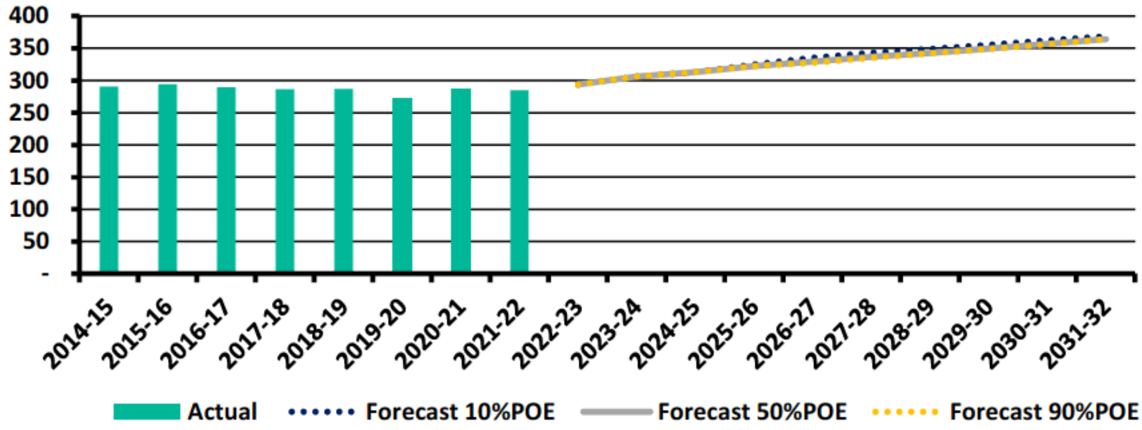
Figure 24 displays the P10 maximum demand forecast and how spot load and EVs impact results. Figure 25 shows the final P10, P50 and P90 maximum demand forecasts.

Figure 24 – Darwin-Katherine, Historical and Forecast P10 Maximum Demand, Spot Loads and EVs



Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)
Note that historical demand is weather normalised, and outage corrected, not observed actual demand

Figure 25 – Darwin-Katherine, Historical and Forecast P10, P50 and P90 Maximum Demand



Source: Energeia Analysis, PWC

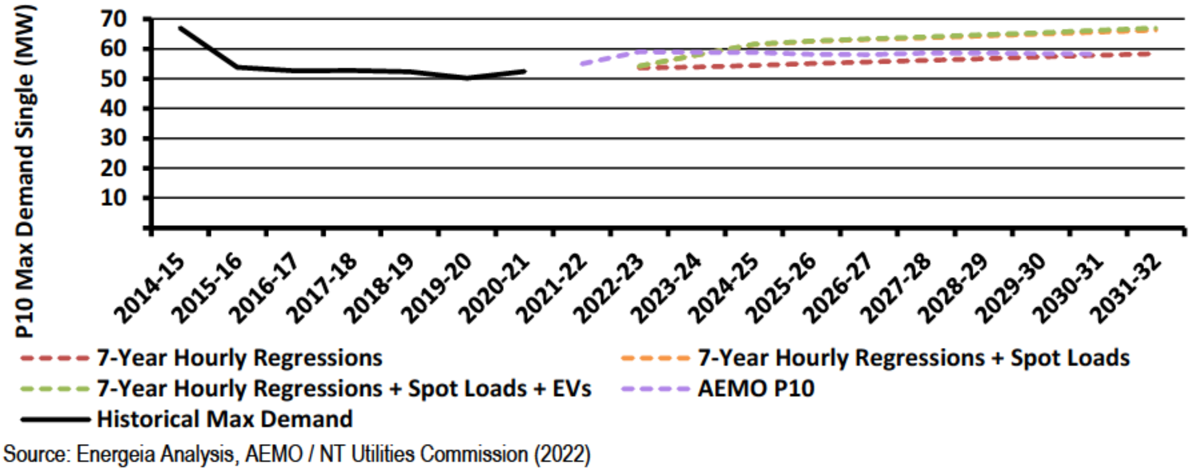
Energeia's forecast predicts a strong growth in maximum demand, slowing in later years as additional spot load capacities decline. Without the spot load and EV impacts, the forecast is almost flat. This indicates that spot load additions are the major driver of maximum demand forecasts and lead to an approximate 85 MW growth in forecast maximum demand between 2022 and 2032.

5.2.2. Alice Springs

For Alice Springs, Energeia selected the 7-year, single variable regression for the maximum demand forecast. Maximums are forecast to firstly occur at 6pm, switching to 5pm from 2024-25 onward. Historically, maximum demand occurred at or between the hours of 3-6pm. Commercial gross connections is the key regression driver at these hours.

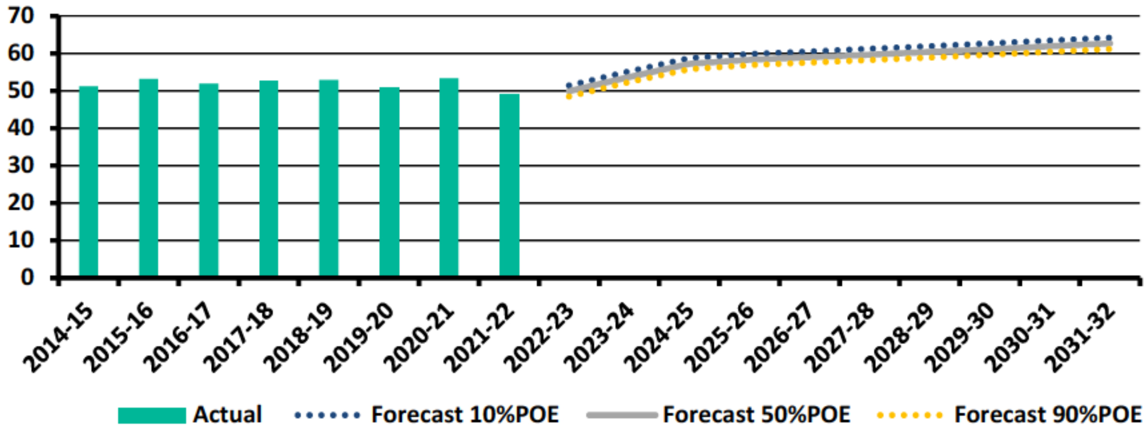
Figure 26 displays the P10 maximum demand forecast and how spot load and EVs impact results. Figure 27 shows the final P10, P50 and P90 maximum demand forecasts.

Figure 26 – Alice Springs, Historical and Forecast P10 Maximum Demand, Spot Loads and EVs



Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)
Note that historical demand is weather normalised, and outage corrected, not observed actual demand

Figure 27 – Alice Springs, Historical and Forecast P10, P50 and P90 Maximum Demand



Source: Energeia Analysis, PWC

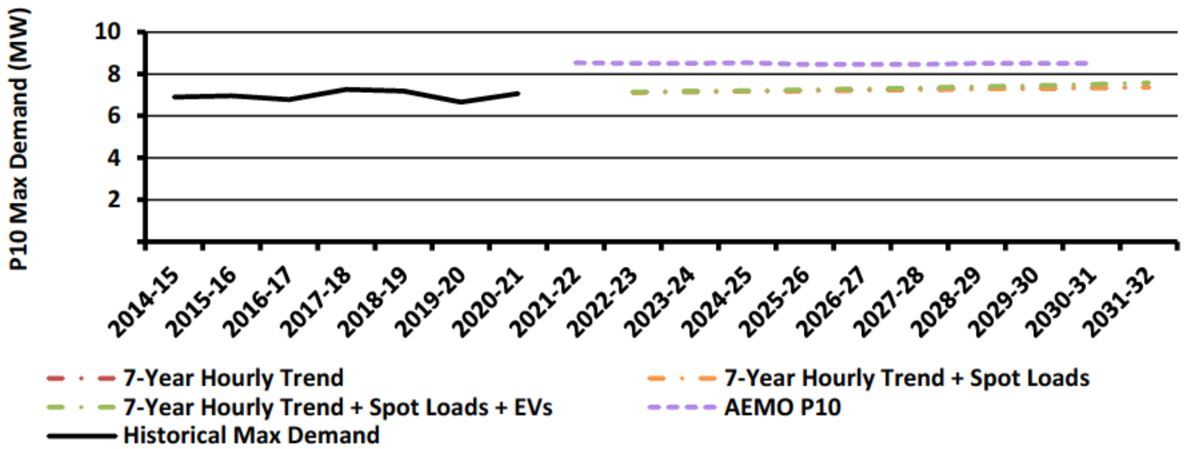
In summary, maximum demand is forecasted to rise quite rapidly due to the [redacted] spot load in the near term, but continue more steadily after 2024-25, reaching nearly 63 MW by 2031-32. This is roughly a 13 MW growth in maximum demand over the 10-year forecast.

5.2.3. Tennant Creek

For Tennant Creek, Energeia selected the 7-year trend for the maximum demand forecast. Maximums were forecast to occur at 5pm. Historically, maximum demand occurred at or between the hours of 2-5pm.

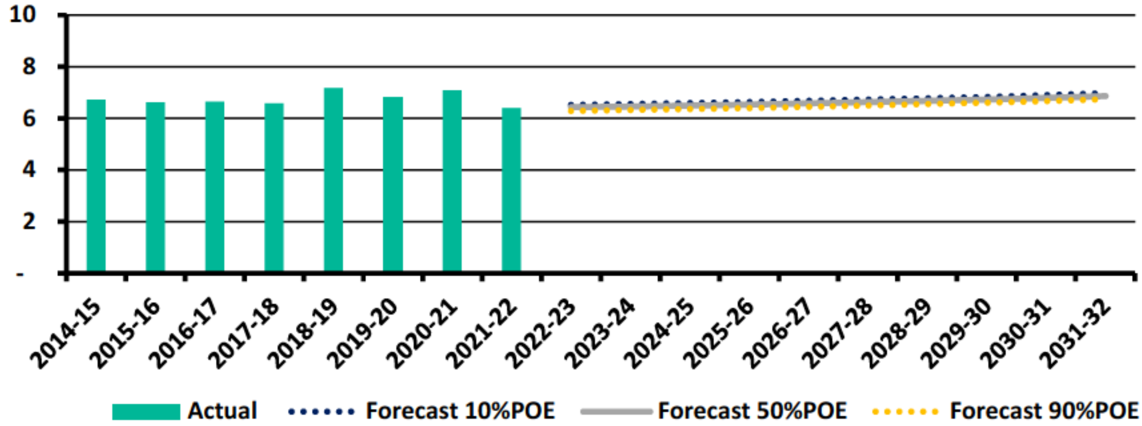
Figure 28 displays the P10 maximum demand forecast and how spot load and EVs impact results. Figure 29 shows the final P10, P50 and P90 maximum demand forecasts.

Figure 28 – Tennant Creek, Historical and Forecast P10 Maximum Demand, Spot Loads and EVs



Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)
Note that historical demand is weather normalised, and outage corrected, not observed actual demand

Figure 29 – Tennant Creek, Historical and Forecast P10, P50 and P90 Maximum Demand



Source: Energeia Analysis, PWC

Forecast maximum demand is mostly constant, but slightly increasing. There were no spot load additions forecast for Tennant Creek. EVs are more noticeable than other regions due to Tennant Creek's small scale, but still relatively insignificant. The forecasted maximum demand reaches almost 7 MW by 2031-32.

Appendix A – Outage Correction

This appendix covers the purpose, method, and outcome of the outage correction methodology.

Purpose

Energeia accounted for outages in the load profiles that occurred as a result of generation, transmission faults and meter data recording errors. This was important to ensure that the demand regressions were not distorted by outages driving observed minimum demand outcomes. Outages occur at random and therefore should not be a factor in forecasting the timing and magnitude minimum or maximum demand on a network.

The data was provided by PWC, with a sample seen in Table A1.

Table A1 – Sample of Outage Record

Date	Power System	Time Off (HH:MM)	Time On (HH:MM)	Incident Duration (HH:MM)	Description	Indicative Cause	Year
03/01/2016	Alice Springs	14:42	15:25	00:43	Alice Springs Power System - UFLS Stage 1A - OSPS Unit 2 Loss of Power	Generation	2016
09/01/2016	Alice Springs	17:08	18:11	01:03	Alice Springs Power System - UFLS Stage 3A - BR-SD 2 Slow Clearance Fault	Networks Transmission	2016
24/01/2016	Darwin-Katherine	18:46	19:05	00:19	Darwin-Katherine Power System - 132kV PK-KA Line Tripped- UFLS Stage 2 in Katherine Island - Weather Lightning Strike	Networks Transmission	2016

Source: PWC

Method

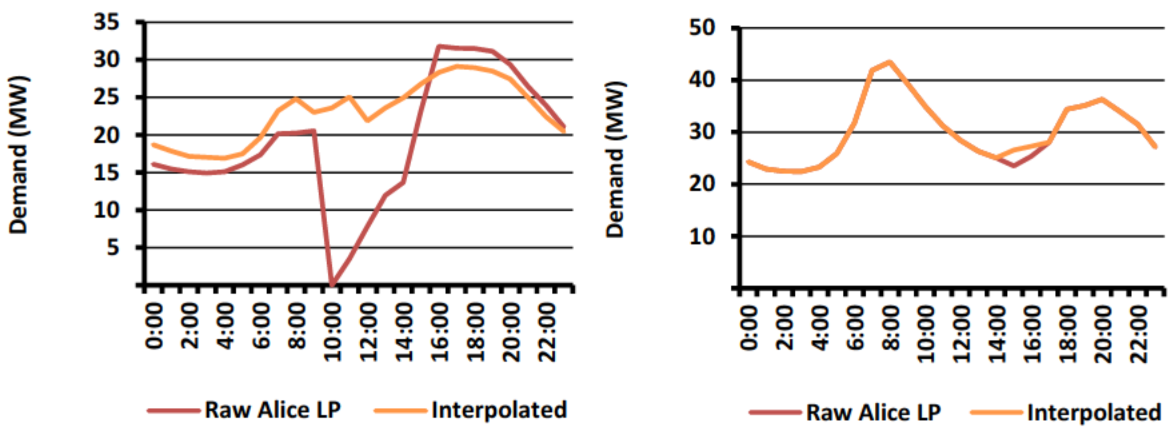
Network outages were corrected under two methods:

- **Short Outages –** Outages lasting less than 2 hours were corrected through linear interpolation
- **Long Outages –** Outages lasting longer than 2 hours were replaced with the comparable day-type one week either before or after, though before was preferred. Note both were considered to account for periods where outages occur more than one week in a row.

Outcome

The impacts of outage correction can be seen in Figure A1.

Figure A1 – Alice Springs Sample Long (Left) and Short (Right) Outage Correction



Source: PWC
Note: Interpolation shows Alice Springs load profiles on the days 9/11/2017 and 20/07/2015 respectively

Appendix B – Spot Load Case Study

This appendix covers the purpose, method, and outcome of the spot load case study.

Purpose

The spot load case study was used to estimate the contribution of future spot load requested additional capacity to forecast minimum and maximum demand in each of PWC's three networks.

Method

The case study was produced using historical data provided from PWC. The subdivisions analysed were Johnston and Zuccoli East/North, connected to the Archer zone substation, and the [redacted], connected to the Palmerston zone substation.

Energeia took this data and used it to find the following ratios:

$$\frac{Change\ in\ Feeder\ Min/Max\ Demand}{Additional\ Spot\ Load\ Connected} * 100\%$$

$$\frac{Feeder\ Demand\ at\ Zone\ Substation\ Min/Max\ Demand}{Feeder\ Annual\ Min/Max\ Demand} * 100\%$$

These two ratios were then multiplied to provide a minimum and maximum demand adjustment factor that describes the following ratio:

$$\frac{Feeder\ Demand\ at\ Zone\ Substation\ Max/Min\ Demand}{Forecast\ Spot\ Load\ Addition} * 100\%$$

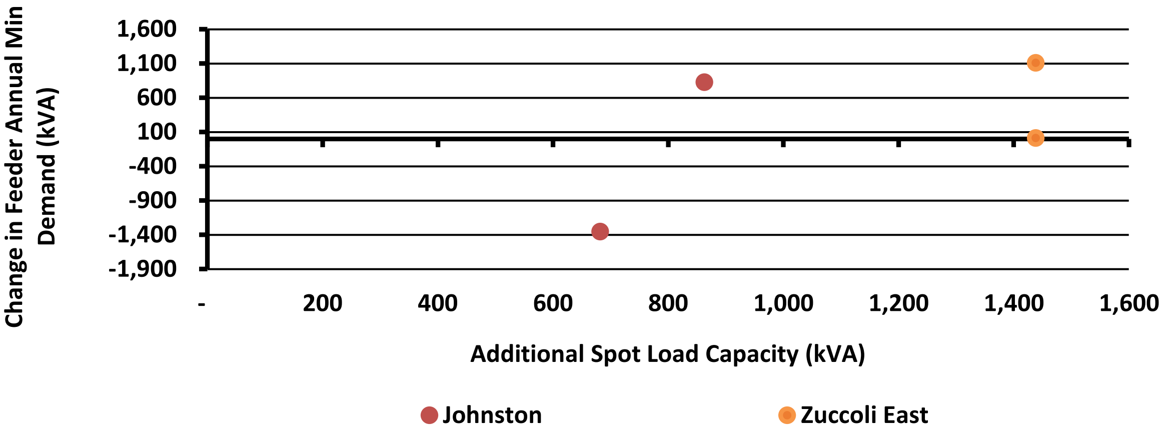
This adjustment factor was multiplied by PWC's forecast spot load additions to provide an estimate of their load contribution at times of minimum and maximum demand.

Outcome

Minimum Demand Adjustment Factor

Figure B1 plots feeder minimum demand against additional spot load capacity. Useable datapoints were scarce for this analysis. The ratio found from this relationship was 36.57%.

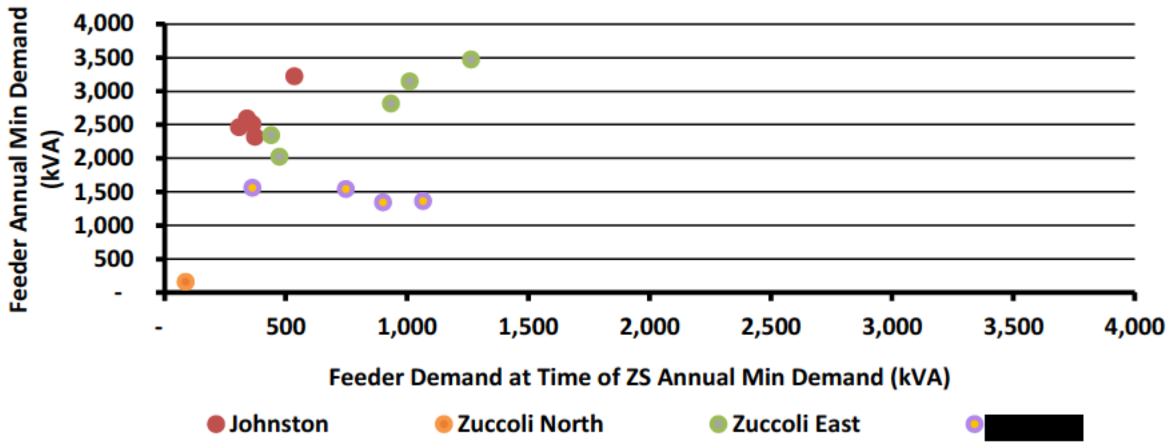
Figure B1 – Case Study Change in Feeder Minimum Demand vs. Additional Spot Load Capacity



Source: PWC, Energeia

Figure B2 feeder demand at zone substation minimum demand against feeder annual minimum. There were more datapoints in this ratio calculation, but no strong relationship. The ratio was found to be 33.75%.

Figure B2 – Case Study Feeder Demand at Zone Substation Minimum Demand vs. Feeder Annual Minimum Demand



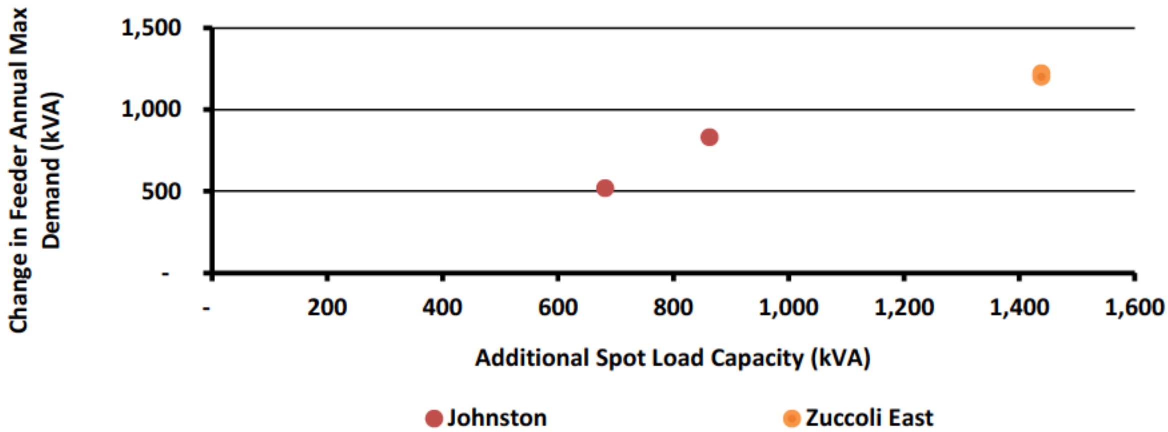
Source: PWC, Energeia

Hence, the minimum demand adjustment factor was estimated as 12.34%. In other words, every 1MW of spot load addition would contribute 0.1234MW of load to forecast minimum demand.

Maximum Demand Adjustment Factor

Figure B3 plots feeder maximum demand against additional spot load capacity. Again, datapoints were scarce for this analysis. The ratio found from this relationship was 77.40%.

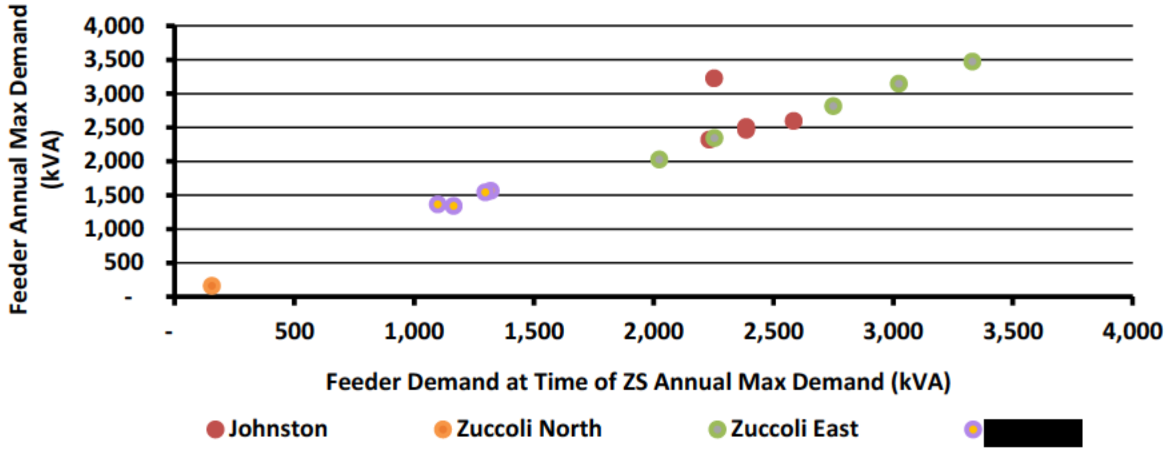
Figure B3 – Case Study Change in Feeder Maximum Demand vs. Additional Spot Load Capacity



Source: PWC, Energeia

Figure B4 plots feeder demand at zone substation maximum demand against feeder annual maximum. A clearer relationship emerges in this plot and the ratio found was 93.38%

Figure B4 – Case Study Feeder Demand at Zone Substation Maximum Demand vs. Feeder Annual Maximum Demand



Source: PWC, Energeia

Hence, the maximum demand adjustment factor was estimated as 72.27%. In other words, every 1MW of spot load addition would contribute 0.7227MW of load to forecast peak demand.

Appendix C – Weather Normalisation

This appendix covers the purpose, method, and outcome of the weather normalisation methodology.

Purpose

Energeia performed weather normalisation on the outage-corrected historical demand to adjust for the impacts of temperature conditions, such as inducing greater space conditioning loads. Exceptionally high or low temperatures in a historical year of data can shift demand in a way that makes it unreasonable to compare to other historical years which may have had more 'normal' weather conditions. Thus, it was important to normalise the temperature impacts on demand to improve regression outcomes.

Method

PWC provided historic daily maximum, minimum temperatures for each network region for all years considered in the forecast inputs. Energeia then calculated daily average temperature as the midpoint between the maximum and minimum temperature.

These daily maximum, minimum and average temperatures were used in regressions with the top and bottom 10% of demand days, by each hour of the day. Note that only hours 12-22 (12pm to 10pm) were considered for maximum demand and hours 0-15 (12am to 3pm) were considered for minimum demand. The regression and normalisation process are detailed in the below steps:

- **Determining weather-dependent load –** The hourly demand was regressed against the minimum, average and maximum observed daily temperature[24] for each hour, by network region. The regression coefficients indicate the % of demand which was strongly correlated with an increase or decrease in temperature.
- **Selecting regression coefficients** –. For each hourly interval, the best regression values were selected, where they were statistically significant (i.e., minimising p-value (<0.05) whilst maximising R^2). If neither were statistically significant, the time interval was treated as uncorrelated to temperature and was excluded from the weather normalisation process.
- **Applying regression coefficients –** Normalising demand for weather variation occurred by removing weather dependent demand from total demand and scaling the demand using regression coefficients to the same temperature (either the P10, P50 or P90 temperature). The final normalised demand was found as the sum of the weather insensitive load and the weather normalised, weather sensitive load.

The following definition of P10, P50 and P90 temperatures were used:

- **P10**: Defined as the temperature during a day where a 10% probability of exceedance occurs, i.e. - the threshold of the warmest 10% of temperatures.
- **P50**: Defined as the temperature during a day where a 50% probability of exceedance occurs.
- **P90**: Defined as the temperature during a day where a 90% probability of exceedance occurs, i.e. - the threshold of the coolest 10% of temperatures.

[24] Weather normalisation could account for other measurements of weather such as humidity and solar irradiance to improve accuracy. At the time of this analysis, other weather data was not available at the required granularity.

Outcome

This section displays the outputs of Energeia's weather normalisation process that were used to produce the demand forecasts, including the temperature model by hour and a demonstration of weather sensitivity.

Best Selected Temperature Model

Minimum Demand

Table C1 – Darwin-Katherine, Minimum Demand, Best Temperature Regression Statistics by Hour

Hour	# of Observations	Independent Variable	Slope	P-values	R^2
0:00	370	Max	2.9536	0.000	12.36%
1:00	370	Average	3.1972	0.000	27.01%
2:00	370	Average	3.0554	0.000	19.56%
3:00	370	Average	2.9395	0.000	20.49%
4:00	370	Average	2.7655	0.000	19.42%
5:00	370	Average	2.4564	0.000	15.31%
6:00	370	Average	1.9655	0.000	7.19%
7:00	370	Average	1.0451	0.110	0.69%
8:00	370	Average	0.1230	0.871	0.01%
9:00	370	Min	-0.4427	0.462	0.15%
10:00	370	Min	-1.1922	0.081	0.82%
11:00	370	Min	-1.7917	0.022	1.41%
12:00	370	Min	-1.6424	0.049	1.05%
13:00	370	Min	-1.2925	0.125	0.64%
14:00	370	Min	-1.0432	0.207	0.43%
15:00	370	Max	2.0198	0.040	1.14%
16:00	370	Max	3.0548	0.000	3.56%
17:00	370	Max	4.2782	0.000	13.36%
18:00	370	Max	4.5759	0.000	26.96%
19:00	370	Average	6.2178	0.000	24.18%
20:00	370	Average	4.5677	0.000	24.38%
21:00	370	Average	4.6400	0.000	28.72%
22:00	370	Average	4.5976	0.000	35.10%
23:00	370	Average	4.4578	0.000	39.37%

Source: Energeia

Table C2 – Alice Springs, Minimum Demand, Best Temperature Regression Statistics by Hour

Hour	# of Observations	Independent Variable	Slope	P-values	R^2
0:00	256	Max	-0.0836	0.007	2.83%
1:00	256	Average	-0.1802	0.000	9.82%
2:00	256	Average	-0.1642	0.000	9.69%
3:00	256	Average	-0.1706	0.000	10.95%
4:00	256	Average	-0.1765	0.000	12.22%
5:00	256	Average	-0.1878	0.000	12.89%
6:00	256	Average	-0.2122	0.000	11.43%
7:00	256	Average	-0.2818	0.000	11.85%
8:00	256	Average	-0.3323	0.000	11.57%
9:00	256	Min	-0.2281	0.000	6.89%
10:00	256	Min	-0.0914	0.075	1.24%
11:00	256	Min	0.0642	0.235	0.55%
12:00	256	Min	0.1989	0.001	3.94%
13:00	256	Min	0.2992	0.000	7.08%
14:00	256	Min	0.3491	0.000	8.21%
15:00	256	Max	0.4622	0.000	16.94%
16:00	256	Max	0.4780	0.000	18.48%
17:00	256	Max	0.4173	0.000	18.36%
18:00	256	Max	0.2422	0.000	9.52%
19:00	256	Average	0.0330	0.559	0.13%
20:00	256	Average	-0.0713	0.183	0.70%
21:00	256	Average	-0.1366	0.007	2.86%
22:00	256	Average	-0.1764	0.000	5.66%
23:00	256	Average	-0.1774	0.000	7.57%

Source: Energeia

Table C3 – Tennant Creek, Minimum Demand, Best Temperature Regression Statistics by Hour

Hour	# of Observations	Independent Variable	Slope	P-values	R^2
0	280	Min	-0.0084	0.160	0.71%
1	280	Average	-0.0098	0.060	1.27%
2	280	Average	-0.0120	0.019	1.95%
3	280	Average	-0.0186	0.001	3.80%
4	280	Average	-0.0219	0.000	5.51%
5	280	Average	-0.0214	0.000	5.38%
6	280	Average	-0.0221	0.000	6.04%
7	280	Min	-0.0291	0.001	3.62%
8	280	Min	-0.0227	0.008	2.49%
9	280	Min	-0.0096	0.186	0.63%
10	280	Min	0.0193	0.008	2.52%
11	280	Min	0.0436	0.000	10.17%
12	280	Min	0.0644	0.000	16.72%
13	280	Min	0.0823	0.000	20.88%
14	280	Min	0.0986	0.000	25.36%
15	280	Min	0.1004	0.000	27.31%
16	280	Min	0.0930	0.000	25.79%
17	280	Average	0.0738	0.000	29.70%
18	280	Average	0.0547	0.000	21.48%
19	280	Average	0.0441	0.000	14.97%
20	280	Average	0.0309	0.000	9.24%
21	280	Average	0.0235	0.000	6.46%
22	280	Average	0.0168	0.002	3.31%
23	280	Min	0.0138	0.031	1.67%

Source: Energeia

Maximum Demand

Table C4 – Darwin-Katherine, Maximum Demand, Best Temperature Regression Statistics by Hour

Hour	# of Observations	Independent Variable	Slope	P-values	R^2
0:00	370	Min	3.0647	0.000	26.03%
1:00	370	Min	2.8593	0.000	20.82%
2:00	370	Min	2.8661	0.000	30.92%
3:00	370	Min	2.9893	0.000	36.24%
4:00	370	Min	3.1009	0.000	42.42%
5:00	370	Min	3.1175	0.000	44.13%
6:00	370	Min	2.8809	0.000	40.48%
7:00	370	Min	2.9599	0.000	25.38%
8:00	370	Min	2.6758	0.000	10.26%
9:00	370	Min	1.8700	0.001	3.15%
10:00	370	Min	0.9693	0.134	0.61%
11:00	370	Min	0.3155	0.656	0.05%
12:00	370	Min	-0.1508	0.834	0.01%
13:00	370	Min	-0.1841	0.794	0.02%
14:00	370	Min	-0.3460	0.606	0.07%
15:00	370	Min	-0.0066	0.991	0.00%
16:00	370	Max	-1.1682	0.197	0.45%
17:00	370	Max	2.1317	0.005	2.10%
18:00	370	Max	3.8538	0.000	7.54%
19:00	370	Max	4.7237	0.000	12.34%
20:00	370	Max	4.2516	0.000	10.26%
21:00	370	Max	3.8544	0.000	9.69%
22:00	370	Max	3.3619	0.000	9.43%
23:00	370	Max	3.1015	0.000	9.66%

Source: Energeia

Table C5 – Alice Springs, Maximum Demand, Best Temperature Regression Statistics by Hour

Hour	# of Observations	Independent Variable	Slope	P-values	R^2
0:00	259	Min	0.3851	0.000	30.16%
1:00	259	Min	0.3529	0.000	30.56%
2:00	259	Min	0.3351	0.000	30.95%
3:00	259	Min	0.3181	0.000	30.60%
4:00	259	Min	0.2895	0.000	27.85%
5:00	259	Min	0.2509	0.000	23.01%
6:00	259	Min	0.1881	0.000	12.14%
7:00	259	Min	0.0784	0.075	1.23%
8:00	259	Min	0.0206	0.693	0.06%
9:00	259	Min	0.0953	0.086	1.15%
10:00	259	Min	0.2047	0.000	5.27%
11:00	259	Min	0.3070	0.000	10.56%
12:00	259	Min	0.3642	0.000	12.91%
13:00	259	Min	0.4370	0.000	17.78%
14:00	259	Min	0.5040	0.000	23.14%
15:00	259	Min	0.5407	0.000	27.74%
16:00	259	Max	0.4538	0.000	20.79%
17:00	259	Max	0.4906	0.000	29.34%
18:00	259	Max	0.4710	0.000	33.30%
19:00	259	Max	0.4155	0.000	28.35%
20:00	259	Max	0.3435	0.000	20.06%
21:00	259	Max	0.3260	0.000	15.38%
22:00	259	Max	0.2868	0.000	12.49%
23:00	259	Max	0.2707	0.000	13.44%

Source: Energeia

Table C6 – Tennant Creek, Maximum Demand, Best Temperature Regression Statistics by Hour

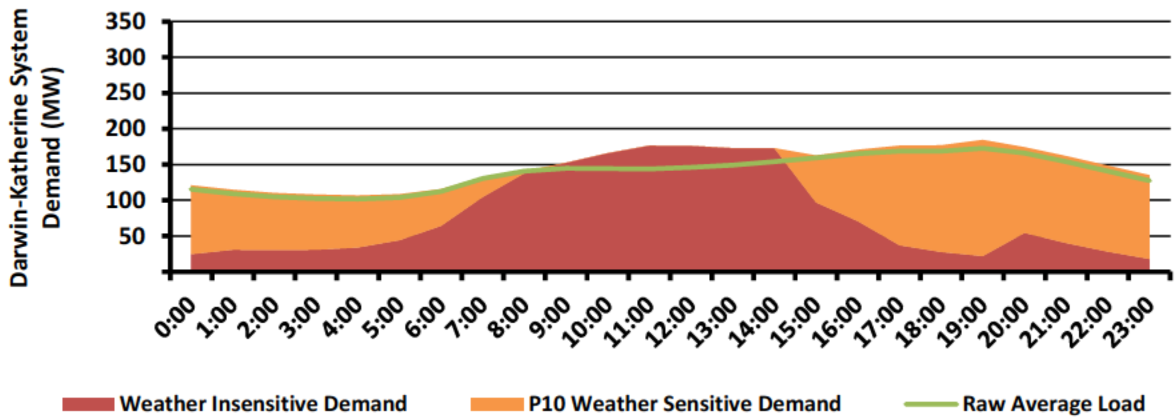
Hour	# of Observations	Independent Variable	Slope	P-values	R^2
0	257	Min	0.0257	0.000	4.99%
1	257	Min	0.0228	0.000	4.70%
2	257	Min	0.0230	0.000	4.99%
3	257	Min	0.0245	0.000	6.01%
4	257	Min	0.0240	0.000	5.90%
5	257	Min	0.0248	0.000	6.39%
6	257	Min	0.0278	0.000	7.86%
7	257	Min	0.0217	0.000	5.25%
8	257	Min	0.0285	0.000	6.66%
9	257	Min	0.0328	0.000	9.04%
10	257	Min	0.0355	0.000	10.25%
11	257	Min	0.0384	0.000	11.40%
12	257	Min	0.0370	0.000	11.16%
13	257	Min	0.0331	0.000	10.15%
14	257	Min	0.0336	0.000	10.60%
15	257	Min	0.0320	0.000	9.30%
16	257	Max	0.0321	0.000	8.08%
17	257	Max	0.0289	0.000	5.83%
18	257	Max	0.0378	0.000	8.17%
19	257	Max	0.0406	0.000	9.12%
20	257	Max	0.0392	0.000	8.53%
21	257	Max	0.0371	0.000	7.10%
22	257	Max	0.0356	0.000	6.90%
23	257	Max	0.0383	0.000	9.14%

Source: Energeia

P10 Demand by Weather Sensitivity

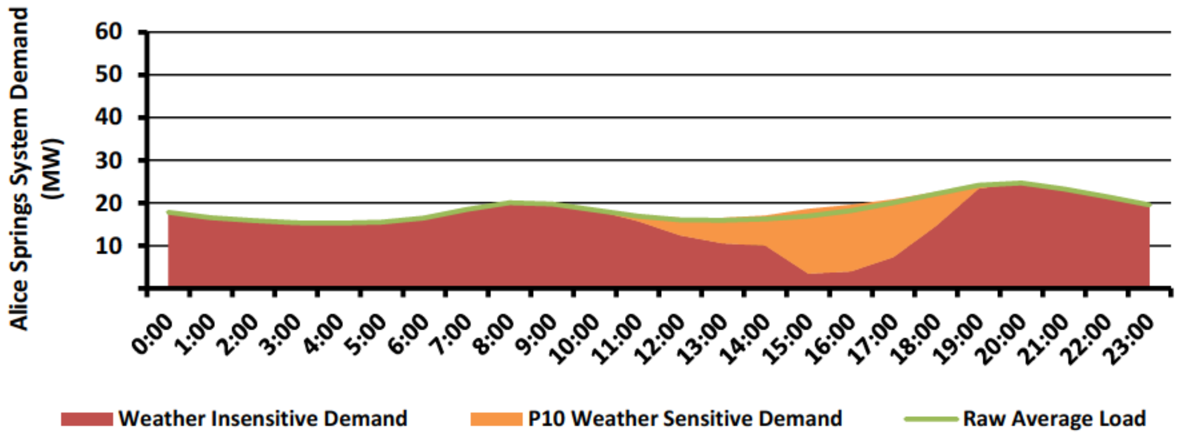
Minimum Demand

Figure C1 – Darwin-Katherine, P10 Minimum Demand Weather Sensitivity by Hour



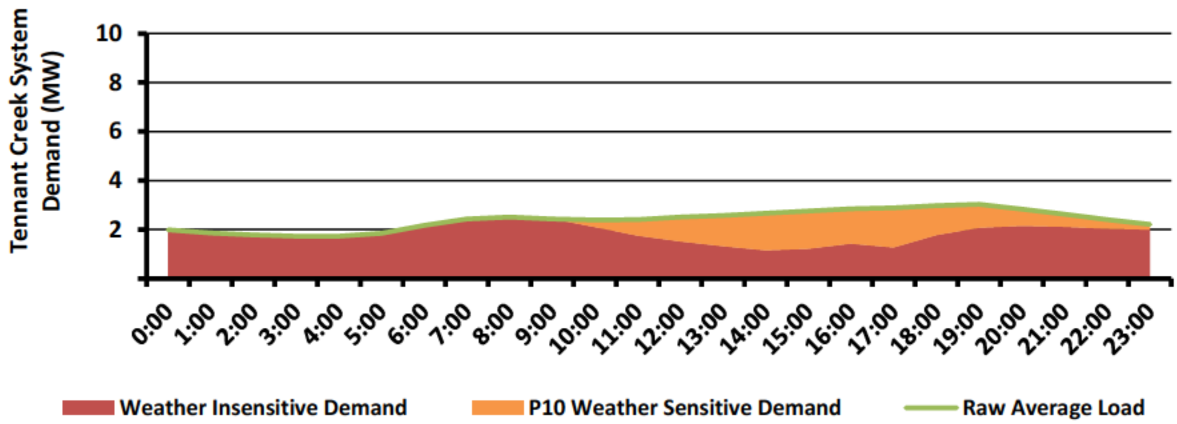
Source: Energeia

Figure C2 – Alice Springs, P10 Minimum Demand Weather Sensitivity by Hour



Source: Energeia

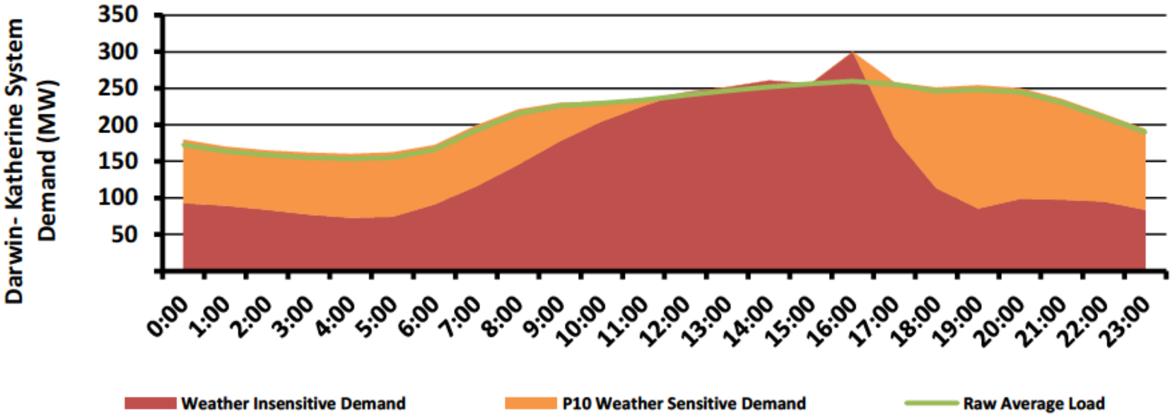
Figure C3 – Tennant Creek, P10 Minimum Demand Weather Sensitivity by Hour



Source: Energeia

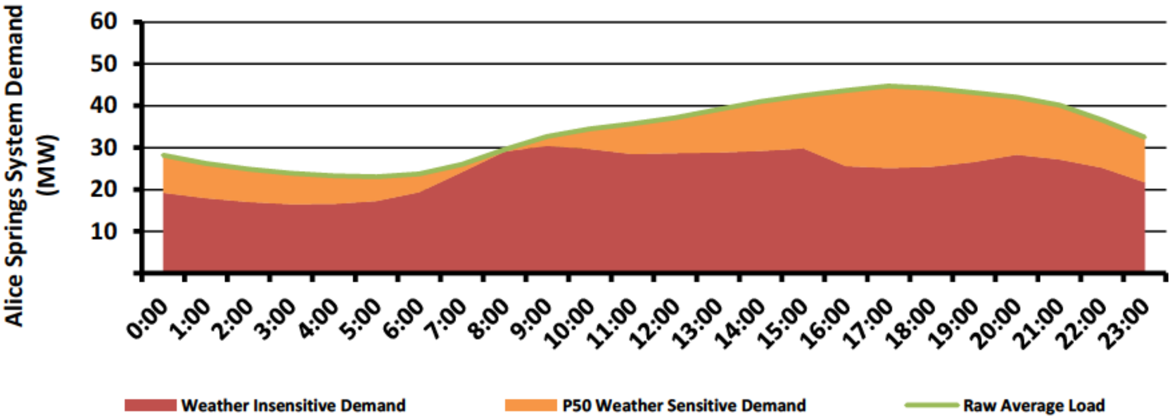
Maximum Demand

Figure C4 – Darwin-Katherine, P10 Maximum Demand Weather Sensitivity by Hour



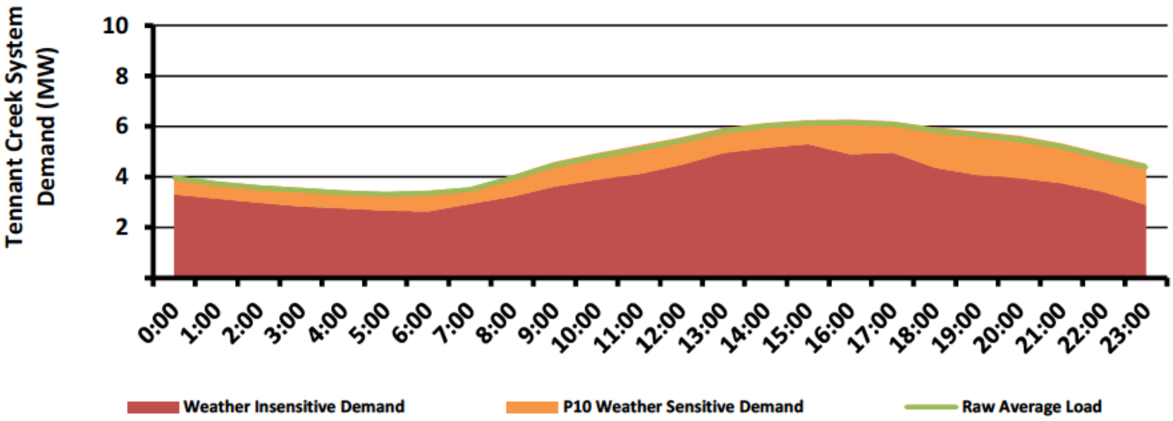
Source: Energeia

Figure C5 – Alice Springs, P10 Maximum Demand Weather Sensitivity by Hour



Source: Energeia

Figure C6 – Tennant Creek, P10 Maximum Demand Weather Sensitivity by Hour

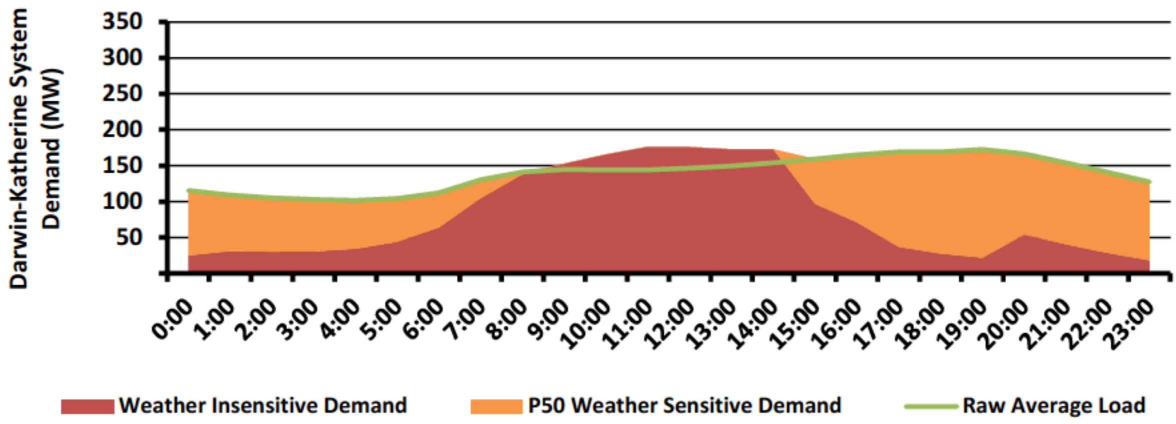


Source: Energeia

P50 Demand by Weather Sensitivity

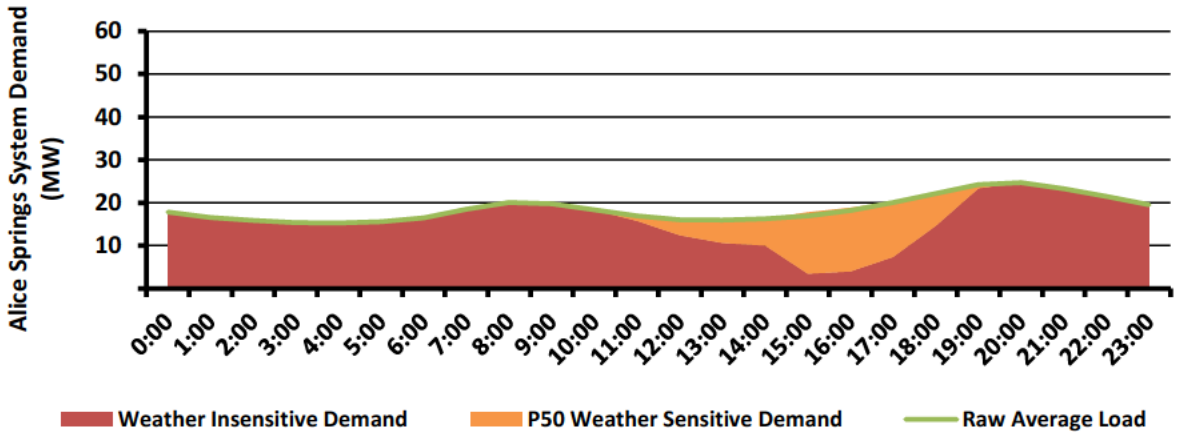
Minimum Demand

Figure C7 – Darwin-Katherine, P50 Minimum Demand Weather Sensitivity by Hour



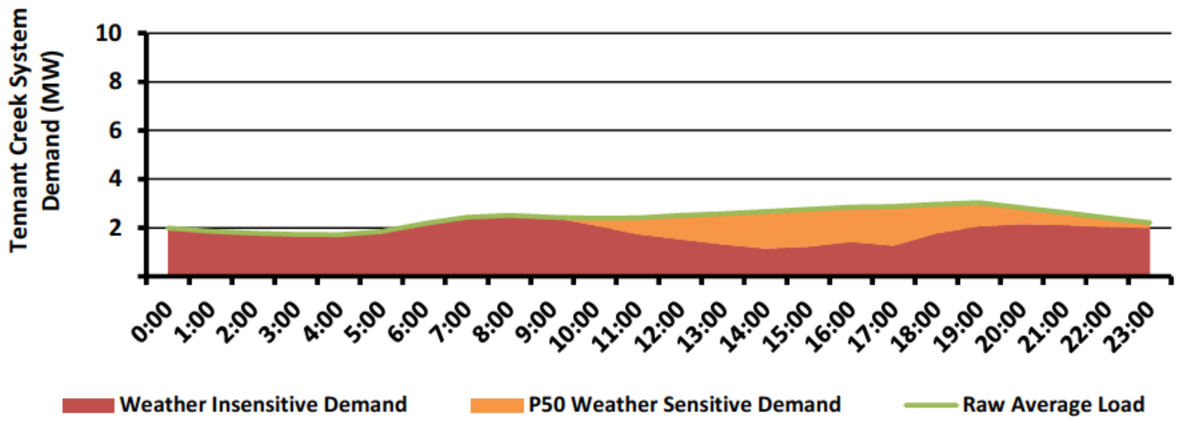
Source: Energeia

Figure C8 – Alice Springs, P50 Minimum Demand Weather Sensitivity by Hour



Source: Energeia

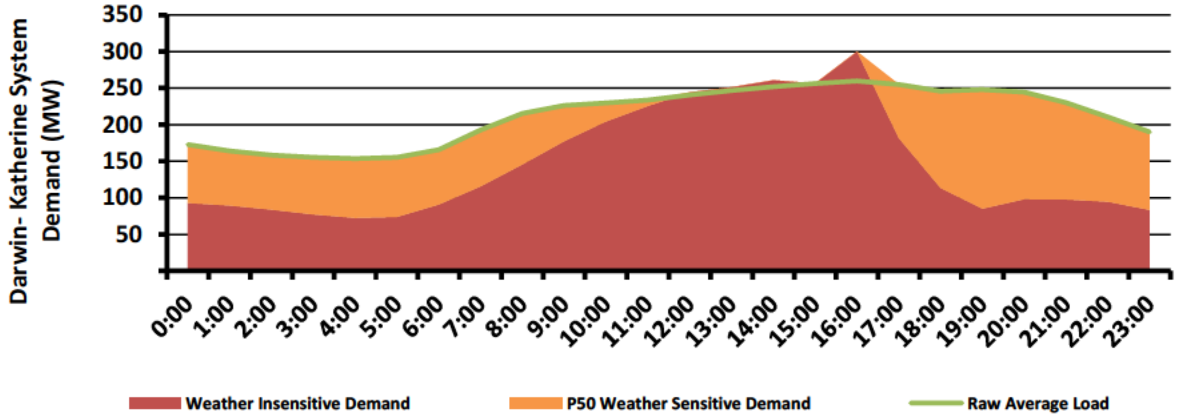
Figure C9 – Tennant Creek, P50 Minimum Demand Weather Sensitivity by Hour



Source: Energeia

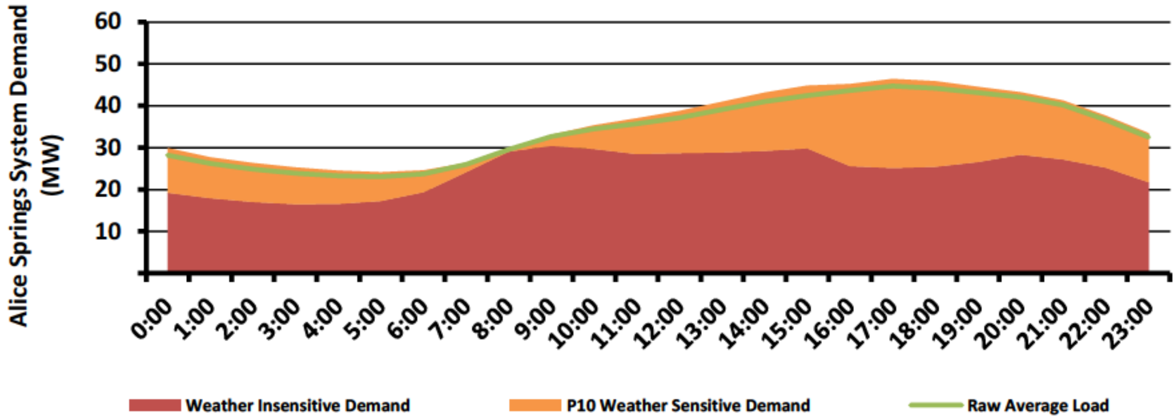
Maximum Demand

Figure C10 – Darwin-Katherine, P50 Maximum Demand Weather Sensitivity by Hour



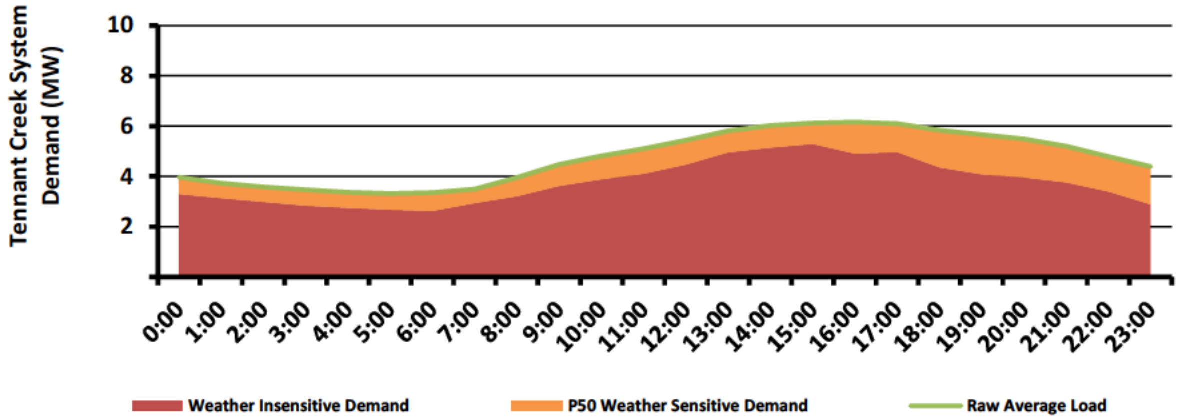
Source: Energeia

Figure C11 – Alice Springs, P50 Maximum Demand Weather Sensitivity by Hour



Source: Energeia

Figure C12 – Tennant Creek, P50 Maximum Demand Weather Sensitivity by Hour

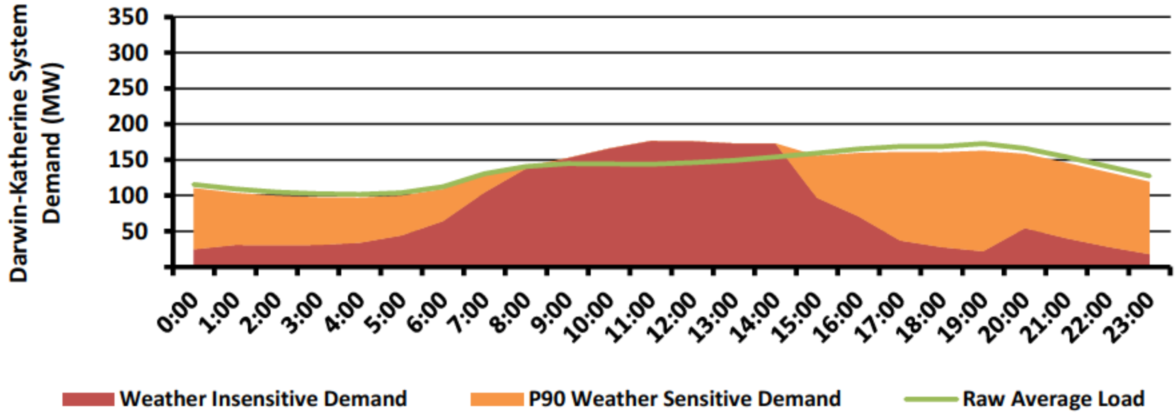


Source: Energeia

P90 Demand by Weather Sensitivity

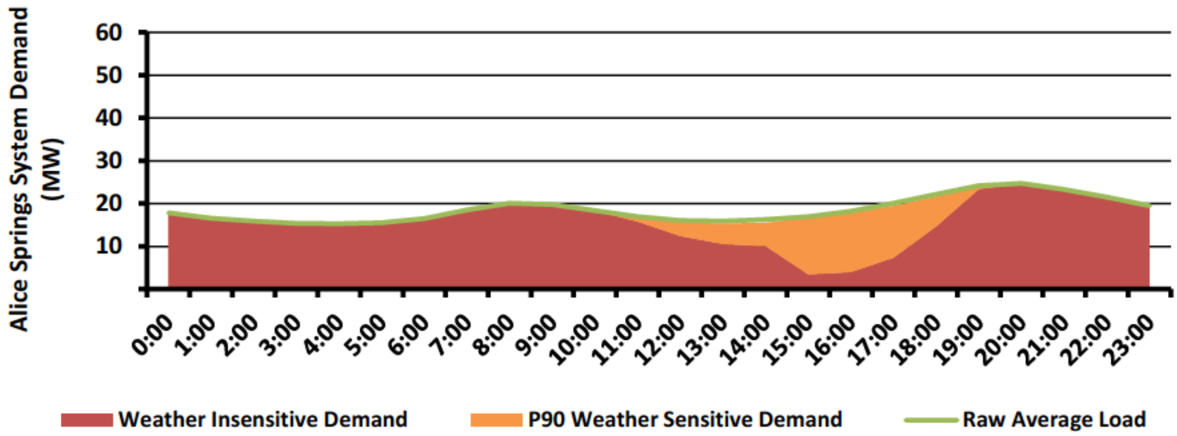
Minimum Demand

Figure C13 – Darwin-Katherine, P90 Minimum Demand Weather Sensitivity by Hour



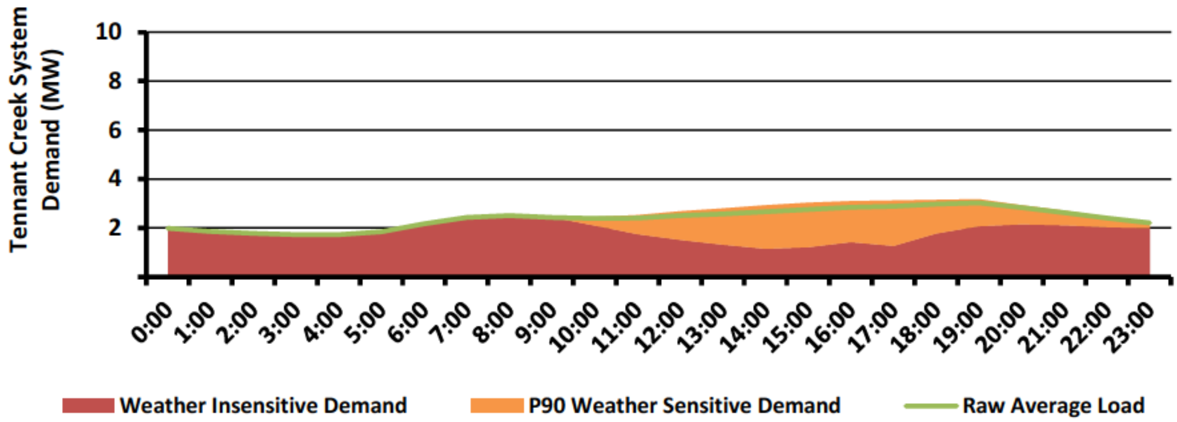
Source: Energeia

Figure C14 – Alice Springs, P90 Minimum Demand Weather Sensitivity by Hour



Source: Energeia

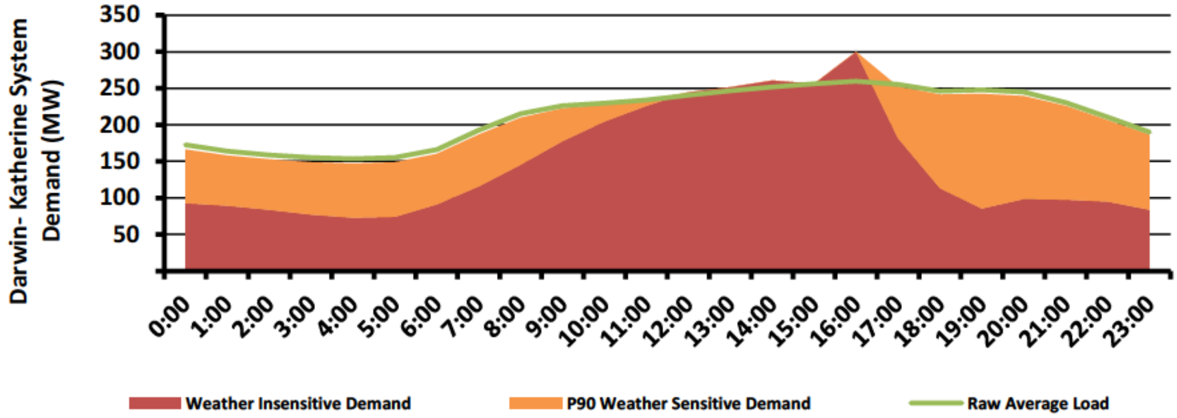
Figure C15 – Tennant Creek, P90 Minimum Demand Weather Sensitivity by Hour



Source: Energeia

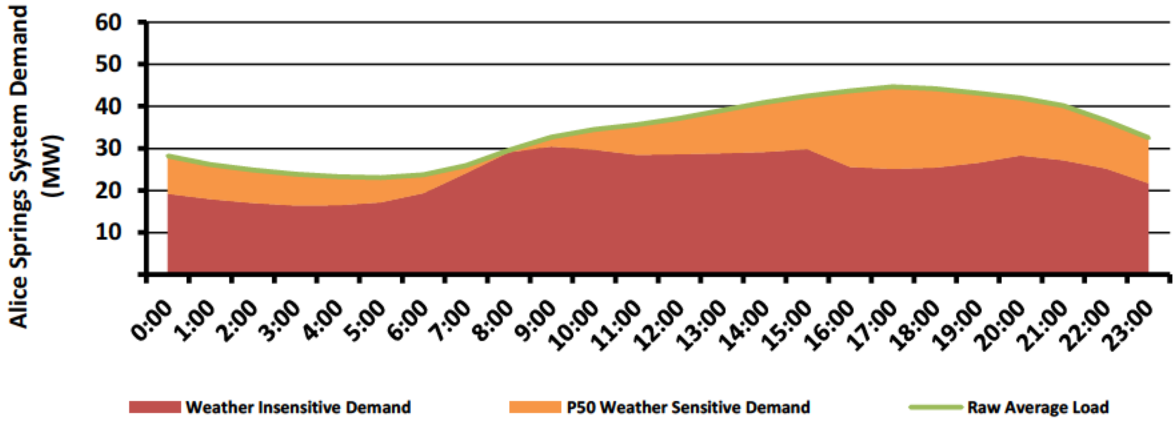
Maximum Demand

Figure C16 – Darwin-Katherine, P90 Maximum Demand Weather Sensitivity by Hour



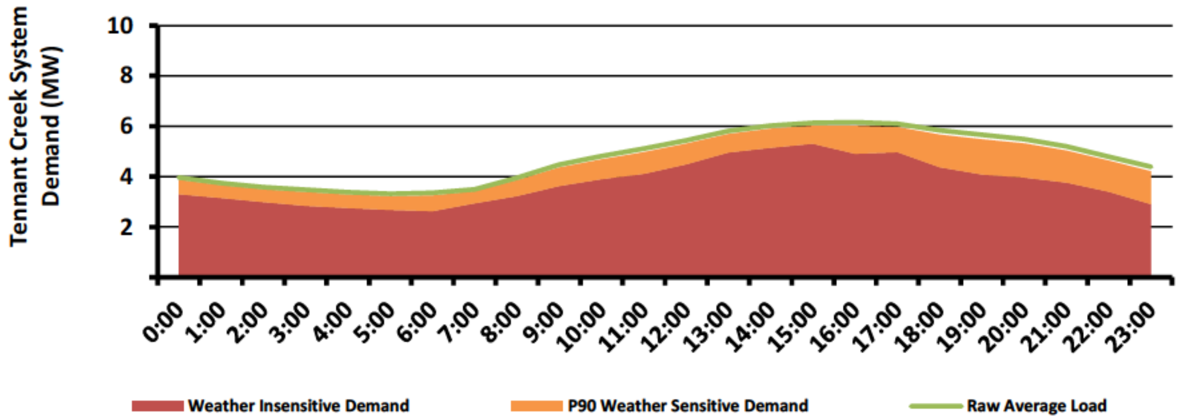
Source: Energeia

Figure C17 – Alice Springs, P90 Maximum Demand Weather Sensitivity by Hour



Source: Energeia

Figure C18 – Tennant Creek, P90 Maximum Demand Weather Sensitivity by Hour



Source: Energeia

Appendix D – Government Forecast Analysis

Energeia conducted an analysis of NT Government population and GSP forecasts, under the hypothesis that they tend towards diverging upward from actuals over time. This appendix covers the findings of this analysis.

Population

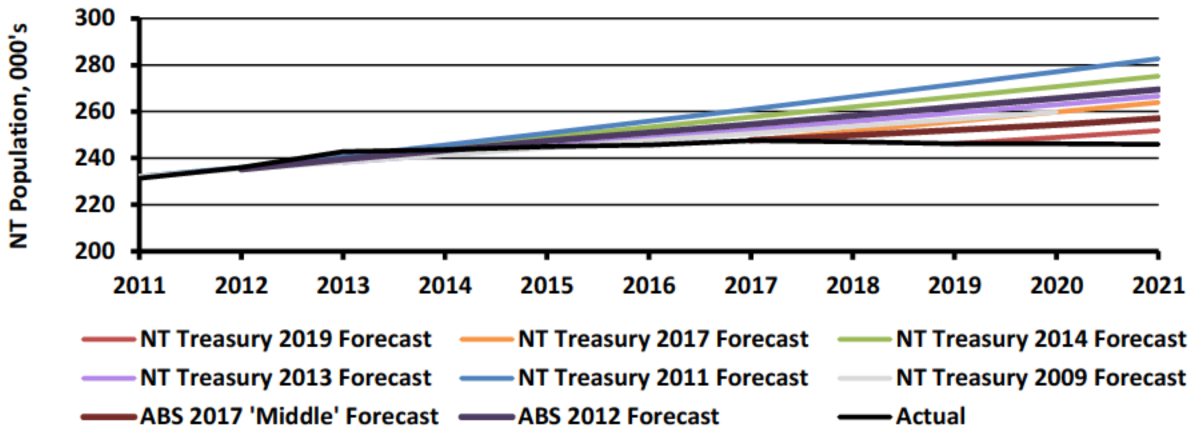
Table D1 and Figure D1 below provide a summary of the forecast errors seen in past Government forecasts for population, comparing the forecast population five years forward with the actual historical population in that year.

Table D1 – 5-Year Forward Population Forecasts, Summary Statistics

	Sample Forecasts	Average Error	Std Dev Error	Max Error	Min Error
NT Treasury 2017	1	+7.3%	-	+7.3%	+7.3%
ABS 2017 'Middle' Forecast	1	+4.6%	-	+4.6%	+4.6%
NT Treasury (2011, 2013, 2014, 2017)	4	+5.8%	+2.3%	+8.2%	+3.5%
ABS 'Middle' (2001, 2012, 2017)	3	+2.7%	+2.4%	+5.0%	+0.3%

Source: Energeia, NT Treasury, ABS

Figure D1 – Historical Government Population Forecasts Compared to Actuals



Source: Energeia, NT Treasury, ABS

The results suggest Energeia's hypothesis to be correct, as all researched forecasts overestimated population. The overestimates ranged from 2.7-7.3% on average at the 5-year ahead mark depending on the source (generally the ABS forecasts outperformed the NT Treasury). Errors propagated over time creating greater discrepancies the further ahead a forecast looks.

GSP

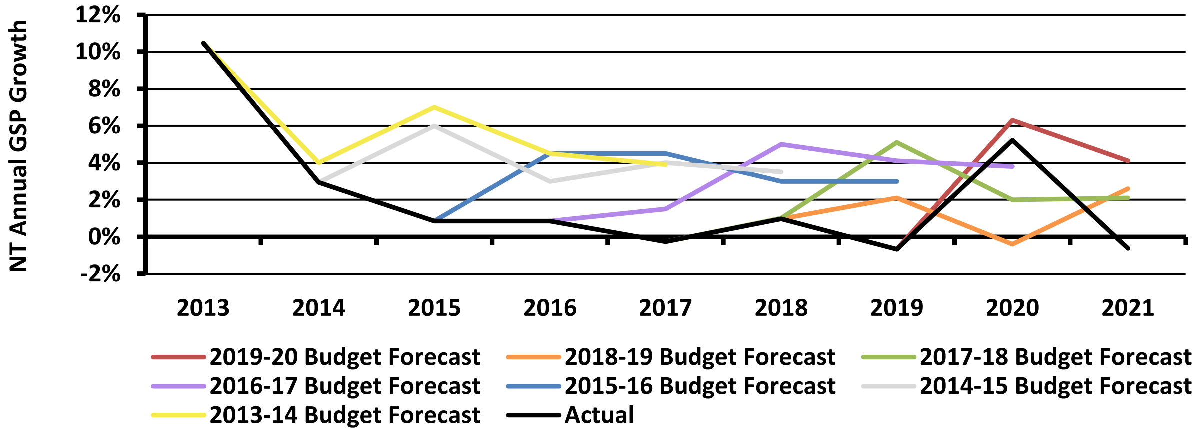
Table D2 provides a summary of the forecast errors seen in past Government forecasts for GSP, comparing the forecast population 4 years looking forward with the actual historical GSP in that year. Additionally, Figure D2 plots the set of researched Government population forecasts alongside actuals.

Table D2 – 4-Year Forward GSP Growth Forecasts, Summary Statistics

Government Forecast	Forecasted Year	Forecasted Growth (%)	Actual Growth (%)	Absolute error (%pts)
2017-18 NT Budget Forecast 2021	2021	2.1%	-0.6%	+2.7
2016-17 NT Budget Forecast 2020	2020	3.8%	5.2%	-1.4
2015-16 NT Budget Forecast 2019	2019	3.0%	-0.7%	+3.7
2014-15 NT Budget Forecast 2018	2018	3.9%	1.0%	+2.5
2013-14 NT Budget Forecast 2017	2017	3.9%	-0.3%	+4.2

Source: Energeia, NT Government Budget Papers

Figure D2 – Historical Government GSP Forecasts Compared to Actuals



Source: Energeia, NT Government Budget Papers

As with population, Energeia's hypothesis appears to be correct for the researched GSP forecasts, as only a single 4-year lookahead forecast was an underestimate – which can be explained by the 2020 GSP being an outlier.

Appendix E – Detailed Results

This appendix covers the detailed results, including the regression parameterisation outcomes and the output range. Note only P90 minimum and P10 maximum demand results are shown, but effectively represent all results as only intercepts change between P10, P50 and P90 regressions. Also, the output range shown is before the addition of spot loads and EVs, and before the adjustment made to include FY22 actuals.

Darwin-Katherine

Regression Parameterisation

Minimum Demand

Table E1 – Darwin-Katherine, Minimum Demand, 7-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
0:00	0.6803	WPI	64.654	15.65188	0.0224
1:00	0.0579	Population	-441.028	0.00215	0.6031
2:00	0.5843	WPI	47.419	19.40226	0.0454
3:00	0.5610	WPI	48.576	18.14321	0.0527
4:00	0.6175	WPI	47.396	18.48483	0.0362
5:00	0.5991	WPI	49.535	18.23258	0.0411
6:00	0.5375	WPI	56.717	16.97063	0.0608
7:00	0.4065	WPI	73.612	11.78148	0.1235
8:00	0.5050	Com_Connections	10.753	0.00757	0.0735
9:00	0.8240	Com_Connections	-61.107	0.01424	0.0047
10:00	0.9337	Total_Solar	158.286	-0.00052	0.0004
11:00	0.9374	Total_Solar	169.088	-0.00063	0.0003
12:00	0.9180	Total_Solar	170.690	-0.00070	0.0007
13:00	0.9297	Total_Solar	164.342	-0.00068	0.0005
14:00	0.9235	Total_Solar	161.656	-0.00066	0.0006
15:00	0.8427	Total_Solar	144.821	-0.00060	0.0035

Source: Energeia

Table E2 – Darwin-Katherine, Minimum Demand, 5-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
0:00	0.5334	WPI	60.845	17.55187	0.1611
1:00	0.4615	WPI	40.281	24.94919	0.2071
2:00	0.5466	WPI	32.138	27.59046	0.1534
3:00	0.5540	WPI	32.121	26.96853	0.1491
4:00	0.6146	WPI	31.127	27.22768	0.1165
5:00	0.6224	WPI	31.429	28.02676	0.1127
6:00	0.6297	WPI	35.094	28.71189	0.1091
7:00	0.5080	WPI	56.520	21.11164	0.1766
8:00	0.3867	Com_Connections	-109.356	0.01753	0.2627
9:00	0.7169	Res_Building	78.023	0.00012	0.0704
10:00	0.8777	Total_Solar	161.160	-0.00056	0.0189
11:00	0.8986	Res_Building	44.523	0.00029	0.0141
12:00	0.8707	Res_Building	28.839	0.00033	0.0205
13:00	0.8850	Res_Building	28.783	0.00031	0.0172
14:00	0.8369	Res_Building	38.598	0.00027	0.0295
15:00	0.6345	Total_Solar	137.910	-0.00051	0.1067

Source: Energeia

Table E3 – Darwin-Katherine, Minimum Demand, 7-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
0:00	0.7081	WPI	Com_Connections	36.6386	11.2209	0.0030	0.27	0.57
1:00	0.3054	WPI	Population	-2558.6449	31.3706	0.0105	0.30	0.26
2:00	0.6534	WPI	Population	-1031.0598	31.9339	0.0043	0.11	0.42
3:00	0.6473	WPI	Population	-1101.2774	31.5042	0.0046	0.11	0.38
4:00	0.7005	WPI	Population	-1047.6686	31.2092	0.0043	0.08	0.35
5:00	0.6820	WPI	Population	-1046.3703	30.9667	0.0044	0.09	0.36
6:00	0.6596	WPI	Population	-1249.8450	32.1526	0.0052	0.09	0.30
7:00	0.4943	WPI	Population	-811.2476	22.0633	0.0035	0.19	0.45
8:00	0.4218	WPI	Total_Solar	88.0779	9.5578	-0.0001	0.33	0.62
9:00	0.9060	Com_Connections	Res_Connections	-221.7664	0.0178	0.0019	0.00	0.14
10:00	0.9917	Res_Connections	Com_Connections	-661.0038	0.0063	0.0322	0.00	0.00
11:00	0.9848	Res_Connections	Com_Connections	-737.3625	0.0065	0.0381	0.00	0.00
12:00	0.9838	Res_Connections	Com_Connections	-891.8158	0.0079	0.0430	0.00	0.00
13:00	0.9772	Res_Connections	Com_Connections	-812.8291	0.0069	0.0414	0.00	0.00
14:00	0.9646	Com_Connections	Res_Connections	-704.0356	0.0390	0.0056	0.00	0.01
15:00	0.8673	Com_Connections	Res_Connections	-550.7556	0.0343	0.0038	0.01	0.18

Source: Energeia

Table E4 – Darwin-Katherine, Minimum Demand, 5-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
0:00	0.8295	Com_Connections	WPI	-107.6630	0.0145	13.7894	0.20	0.20
1:00	0.6616	WPI	Com_Connections	-171.3438	20.2240	0.0182	0.33	0.39
2:00	0.7410	Com_Connections	WPI	-179.9062	0.0183	22.8559	0.35	0.24
3:00	0.7442	Com_Connections	WPI	-171.5294	0.0176	22.4214	0.35	0.24
4:00	0.7672	Com_Connections	WPI	-143.6497	0.0151	23.3253	0.37	0.20
5:00	0.7111	WPI	Com_Connections	-104.9018	24.9828	0.0118	0.22	0.52
6:00	0.7172	WPI	Com_Connections	-102.8913	25.6310	0.0119	0.21	0.51
7:00	0.5548	Com_Connections	WPI	-26.0690	0.0071	19.2676	0.69	0.32
8:00	0.4061	Com_Connections	WPI	-103.0970	0.0164	3.8249	0.41	0.82
9:00	0.7858	Com_Connections	Res_Connections	-287.9940	0.0241	0.0017	0.14	0.32
10:00	0.9985	Res_Connections	Res_Building	-146.1843	0.0034	0.0002	0.00	0.00
11:00	0.9819	Com_Connections	Res_Connections	-812.9996	0.0457	0.0062	0.02	0.02
12:00	0.9934	Res_Connections	Res_Building	-198.6029	0.0040	0.0003	0.03	0.01
13:00	0.9675	Res_Connections	Com_Connections	-909.2607	0.0066	0.0509	0.03	0.03
14:00	0.9254	Res_Connections	Com_Connections	-793.7521	0.0053	0.0478	0.08	0.06
15:00	0.7366	Res_Connections	Com_Connections	-698.5665	0.0033	0.0491	0.39	0.16

Source: Energeia

Maximum Demand

Table E5 – Darwin-Katherine, Maximum Demand, 7-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
12:00	0.9711	Total_Solar	287.8315	-0.0006	0.0000
13:00	0.9407	Total_Solar	294.0295	-0.0005	0.0003
14:00	0.9031	Total_Solar	299.8351	-0.0004	0.0010
15:00	0.8940	Total_Solar	287.6233	-0.0003	0.0013
16:00	0.8603	Total_Solar	330.9065	-0.0003	0.0026
17:00	0.4451	Total_Solar	285.5490	-0.0001	0.1016
18:00	0.0326	Total_Solar	274.6953	0.0000	0.6987
19:00	0.1490	Population	-254.5055	0.0022	0.3925
20:00	0.0590	Population	36.0994	0.0010	0.5996
21:00	0.0180	Population	113.3854	0.0006	0.7744
22:00	0.1310	Com_Connections	196.8365	0.0028	0.4250

Source: Energeia

Table E6 – Darwin-Katherine, Maximum Demand, 5-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
12:00	0.9931	Total_Solar	287.2990	-0.0006	0.0002
13:00	0.8980	Total_Solar	292.9357	-0.0005	0.0143
14:00	0.9037	Res_Building	217.3526	0.0002	0.0131
15:00	0.8050	Res_Building	237.7268	0.0001	0.0389
16:00	0.7397	Total_Solar	327.8908	-0.0002	0.0615
17:00	0.2753	Total_Solar	284.8841	-0.0001	0.3640
18:00	0.4010	Com_Connections	75.9280	0.0162	0.2515
19:00	0.5480	Com_Connections	49.1329	0.0188	0.1525
20:00	0.7704	Com_Connections	65.7036	0.0170	0.0504
21:00	0.3352	Com_Connections	86.0100	0.0139	0.3064
22:00	0.4288	Com_Connections	67.2050	0.0135	0.2304

Source: Energeia

Table E7 – Darwin-Katherine, Maximum Demand, 7-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
12:00	0.9332	Com_Building	Res_Connections	-72.7140	0.0001	0.0046	0.0018	0.0302
13:00	0.9024	Res_Connections	Com_Connections	-458.3594	0.0053	0.0318	0.0393	0.0038
14:00	0.9512	Res_Building	Population	-1574.2009	0.0001	0.0073	0.0025	0.0444
15:00	0.9447	Total_Solar	Com_Connections	207.4447	-0.0002	0.0059	0.0490	0.1280
16:00	0.8571	Total Build	Res_Connections	156.2272	0.0000	0.0022	0.0082	0.0990
17:00	0.4061	Com_Connections	Res_Connections	93.1801	0.0082	0.0013	0.1780	0.4691
18:00	0.1433	Com_Connections	Population	-681.9483	0.0071	0.0035	0.4600	0.5026
19:00	0.2744	Population	Com_Connections	-1208.1846	0.0057	0.0073	0.3071	0.4524
20:00	0.3250	Population	Com_Connections	-941.2534	0.0046	0.0075	0.2385	0.2776
21:00	0.1203	Com_Connections	Population	-545.4173	0.0051	0.0030	0.5326	0.5033
22:00	0.2053	Com_Connections	Population	-423.7688	0.0065	0.0023	0.4043	0.5740

Source: Energeia

Table E8 – Darwin-Katherine, Maximum Demand, 5-Year, Multi Variable Regression Statistics by Hour

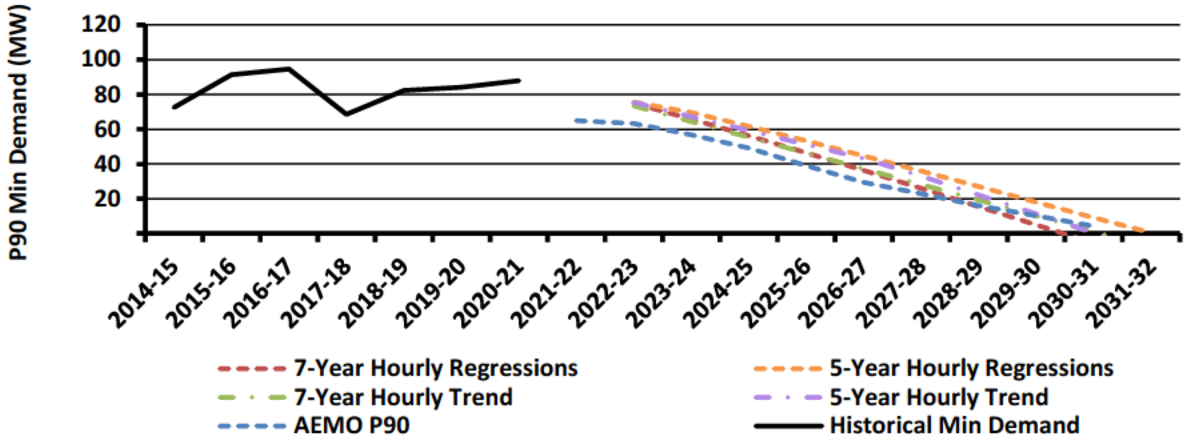
Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
12:00	0.9231	Com_Connections	Res_Connections	-530.2766	0.0369	0.0053	0.0764	0.0660
13:00	0.9115	Res_Connections	Com_Connections	-527.0518	0.0048	0.0399	0.0887	0.0747
14:00	0.9386	Res_Connections	Com_Connections	-321.8674	0.0033	0.0320	0.0744	0.0461
15:00	0.9495	Com_Connections	Total_Solar	127.2056	0.0123	-0.0001	0.1196	0.0954
16:00	0.7594	Com_Connections	Res_Connections	-5.3167	0.0117	0.0028	0.3403	0.1537
17:00	0.3453	Res_Connections	Com_Connections	49.5173	0.0010	0.0135	0.6597	0.4561
18:00	0.2211	WPI	Res_Building	245.3130	6.0309	0.0001	0.7312	0.5523
19:00	0.3174	Res_Building	WPI	244.9297	0.0001	7.2150	0.4610	0.6620
20:00	0.5953	WPI	Res_Building	237.2425	8.0424	0.0001	0.4359	0.2544
21:00	0.1449	Res_Building	WPI	232.8575	0.0000	5.6590	0.6602	0.7429
22:00	0.5499	Com_Connections	GSP	-44.5806	0.0168	0.0028	0.2591	0.5396

Source: Energeia

Output Range

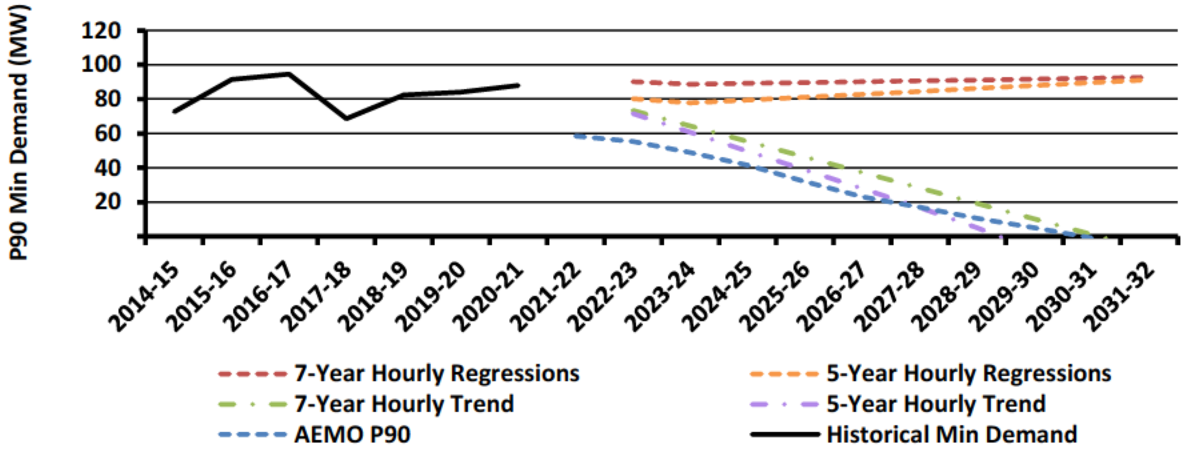
Minimum Demand

Figure E1 – Darwin-Katherine, Minimum Demand, Single Variable Regression Forecast Range



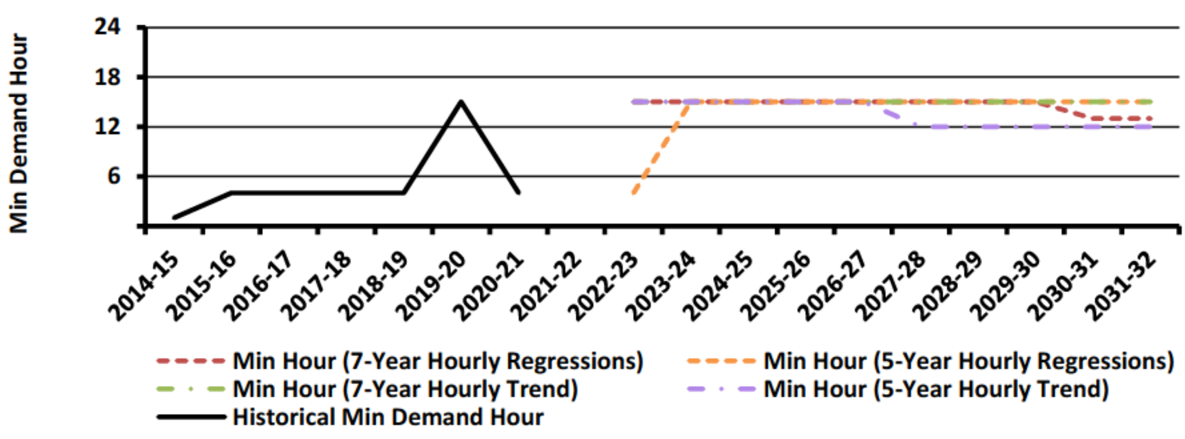
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E2 – Darwin-Katherine, Minimum Demand, Multi Variable Regression Forecast Range



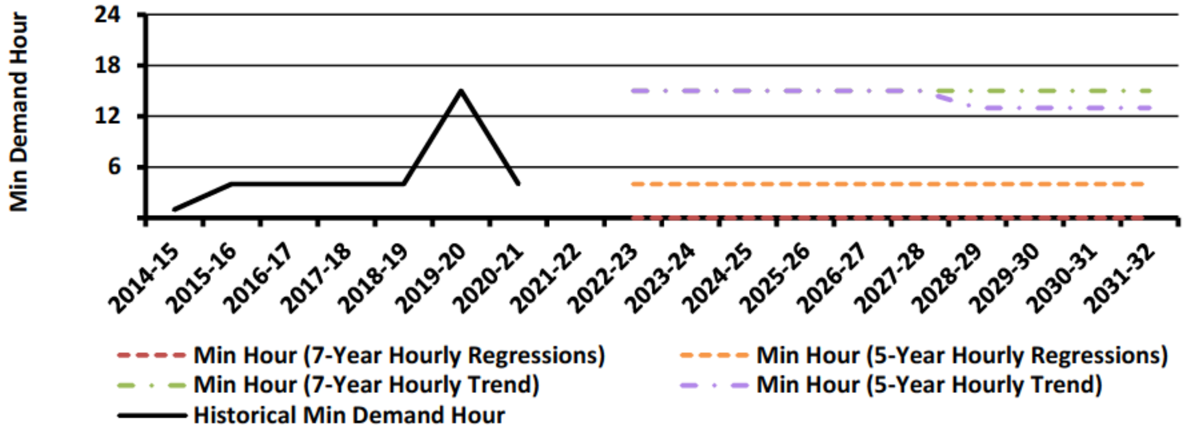
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E3 – Darwin-Katherine, Minimum Demand, Single Variable Regression Hour Range



Source: Energeia

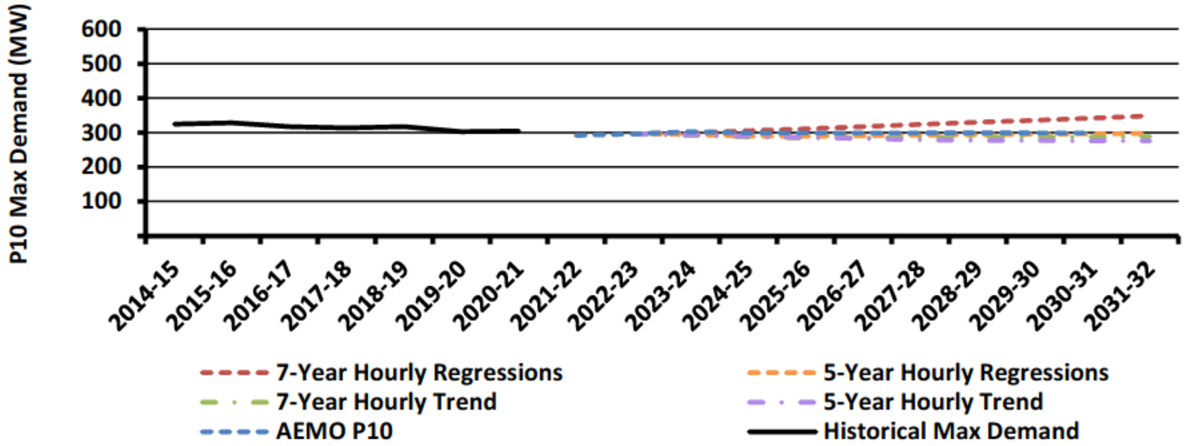
Figure E4 – Darwin-Katherine, Minimum Demand, Multi Variable Regression Hour Range



Source: Energeia

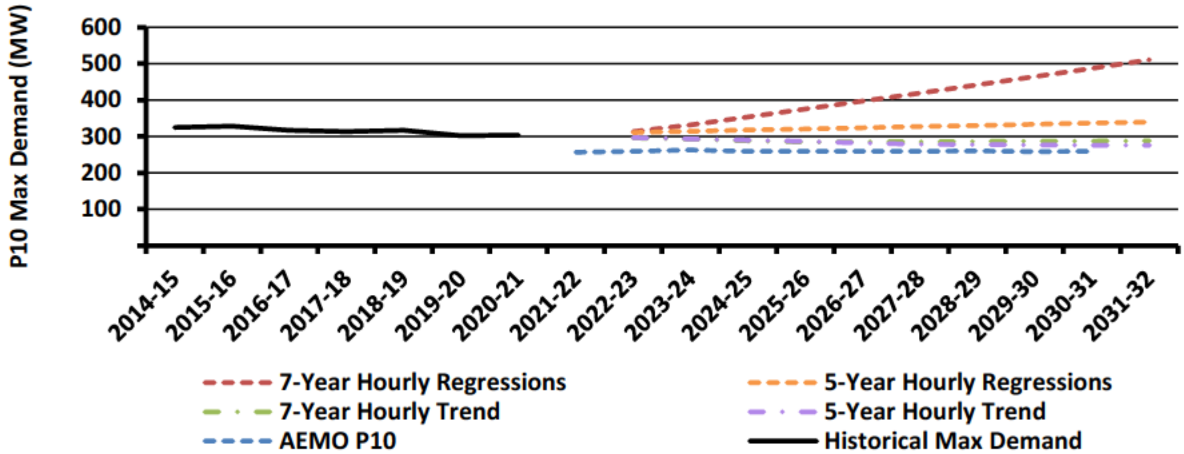
Maximum Demand

Figure E5 – Darwin-Katherine, Maximum Demand, Single Variable Regression Forecast Range



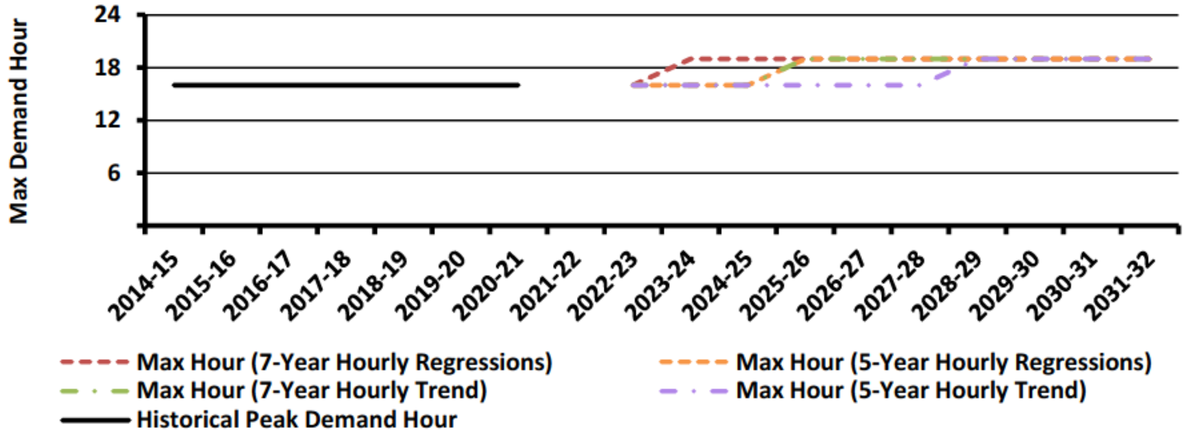
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E6 – Darwin-Katherine, Maximum Demand, Multi Variable Regression Forecast Range



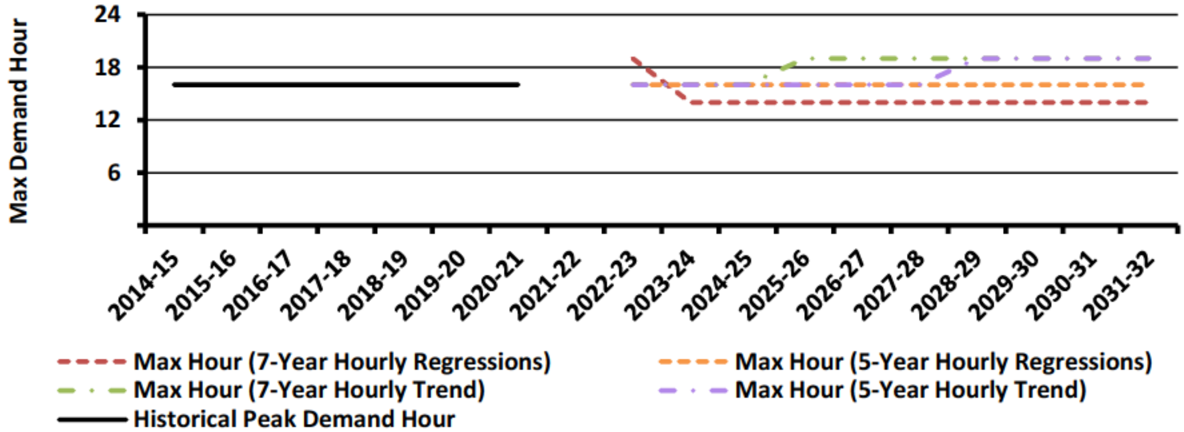
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E7 – Darwin-Katherine, Maximum Demand, Single Variable Regression Hour Range



Source: Energeia

Figure E8 – Darwin-Katherine, Maximum Demand, Multi Variable Regression Hour Range



Source: Energeia

Alice Springs

Regression Parameterisation

Minimum Demand

Table E9 – Alice Springs, Minimum Demand, 7-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
0:00	0.2847	GSP	-40.104	0.00216	0.2174
1:00	0.2829	GSP	-35.808	0.00196	0.2192
2:00	0.2078	GSP	-24.614	0.00150	0.3040
3:00	0.2111	GSP	-23.841	0.00145	0.2997
4:00	0.1905	GSP	-20.669	0.00132	0.3276
5:00	0.1760	GSP	-19.765	0.00128	0.3488
6:00	0.1130	GSP	-15.906	0.00114	0.4610
7:00	0.1140	GSP	-18.035	0.00126	0.4590
8:00	0.0332	GSP	-0.974	0.00058	0.6957
9:00	0.0190	Res_Connections	3.383	0.00016	0.7684
10:00	0.0463	Com_Building	11.425	0.00000	0.6431
11:00	0.3104	Res_Building	8.891	0.00001	0.1939
12:00	0.5888	Res_Building	6.378	0.00001	0.0441
13:00	0.5205	Res_Building	5.521	0.00001	0.0672
14:00	0.4669	Res_Building	5.792	0.00001	0.0906
15:00	0.6227	Com_Connections	-3.279	0.00137	0.0349

Source: Energeia

Table E10 – Alice Springs, Minimum Demand, 5-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
0:00	0.3676	GSP	-73.602	0.00346	0.2784
1:00	0.4012	GSP	-69.737	0.00327	0.2513
2:00	0.4345	GSP	-67.099	0.00315	0.2263
3:00	0.4672	GSP	-66.435	0.00310	0.2033
4:00	0.4043	GSP	-57.124	0.00273	0.2489
5:00	0.3459	GSP	-53.577	0.00259	0.2969
6:00	0.2803	GSP	-52.825	0.00258	0.3589
7:00	0.2488	GSP	-55.154	0.00270	0.3923
8:00	0.1722	GSP	-34.884	0.00190	0.4872
9:00	0.1081	Res_Connections	-15.529	0.00046	0.5890
10:00	0.2743	Res_Connections	-29.478	0.00067	0.3650
11:00	0.5462	Res_Connections	-39.179	0.00081	0.1536
12:00	0.6531	Res_Connections	-39.501	0.00080	0.0979
13:00	0.5478	Res_Connections	-38.020	0.00075	0.1527
14:00	0.1582	Res_Connections	-18.941	0.00045	0.5073
15:00	0.0000	Res_Connections	13.405	0.00000	1.0000

Source: Energeia

Table E11 – Alice Springs, Minimum Demand, 7-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
0:00	0.2923	GSP	Res_Building	-54.5651	0.0027	0.0000	0.43	0.85
1:00	0.2992	GSP	Com_Building	-52.7248	0.0026	0.0000	0.37	0.78
2:00	0.2709	GSP	Res_Building	-58.5651	0.0027	0.0000	0.34	0.59
3:00	0.2904	GSP	Res_Building	-60.3977	0.0028	0.0000	0.31	0.54
4:00	0.2424	GSP	Com_Building	-45.4066	0.0022	0.0000	0.36	0.63
5:00	0.2035	GSP	Total Build	-39.4990	0.0020	0.0000	0.45	0.73
6:00	0.1392	GSP	Com_Building	-35.6965	0.0019	0.0000	0.51	0.74
7:00	0.1286	GSP	Com_Building	-34.2758	0.0019	0.0000	0.55	0.81
8:00	0.0591	Com_Building	GSP	-19.4452	0.0000	0.0013	0.76	0.65
9:00	0.0544	Com_Building	Res_Connections	-6.3450	0.0000	0.0003	0.72	0.68
10:00	0.1671	Com_Building	Res_Connections	-16.2585	0.0000	0.0004	0.46	0.49
11:00	0.4369	Res_Building	Res_Connections	-20.1298	0.0000	0.0005	0.15	0.40
12:00	0.6384	Res_Building	Res_Connections	-16.8593	0.0000	0.0004	0.06	0.50
13:00	0.4811	Com_Connections	Res_Connections	-60.2799	0.0034	0.0005	0.14	0.50
14:00	0.2983	Total_Solar	WPI	7.8031	0.0000	2.1584	0.50	0.62
15:00	0.6017	Res_Building	WPI	10.4428	0.0000	0.9896	0.33	0.54

Source: Energeia

Table E12 – Alice Springs, Minimum Demand, 5-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
0:00	0.5446	GSP	Res_Connections	-228.3616	0.0062	0.0014	0.27	0.47
1:00	0.5619	GSP	Res_Connections	-203.3097	0.0057	0.0012	0.27	0.48
2:00	0.6500	GSP	Res_Connections	-210.0429	0.0057	0.0012	0.20	0.38
3:00	0.6475	GSP	Res_Connections	-190.7710	0.0053	0.0011	0.21	0.42
4:00	0.6023	GSP	Res_Connections	-180.4144	0.0050	0.0011	0.23	0.42
5:00	0.5294	GSP	Res_Connections	-175.4510	0.0048	0.0011	0.28	0.47
6:00	0.5129	GSP	Res_Connections	-204.1590	0.0053	0.0013	0.29	0.43
7:00	0.5321	GSP	Res_Connections	-240.8846	0.0060	0.0016	0.27	0.39
8:00	0.6034	GSP	Res_Connections	-228.5132	0.0054	0.0017	0.23	0.28
9:00	0.5997	Res_Connections	GSP	-188.6865	0.0016	0.0041	0.24	0.26
10:00	0.6763	Res_Connections	GSP	-173.6480	0.0016	0.0034	0.18	0.26
11:00	0.7832	Res_Connections	GSP	-133.7865	0.0014	0.0022	0.12	0.28
12:00	0.9044	GSP	Res_Connections	-127.4964	0.0021	0.0014	0.15	0.05
13:00	0.6604	Res_Connections	GSP	-98.7098	0.0011	0.0014	0.22	0.50
14:00	0.5773	Res_Connections	GSP	-149.4683	0.0013	0.0031	0.24	0.29
15:00	None							

Source: Energeia

Maximum Demand

Table E13 – Alice Springs, Maximum Demand, 7-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
12:00	0.7139	Total_Solar	48.2324	-0.0001	0.0167
13:00	0.4316	Com_Connections	31.8558	0.0012	0.1089
14:00	0.5431	WPI	43.8864	2.7533	0.0588
15:00	0.7804	Total_Solar	53.5237	0.0000	0.0084
16:00	0.6754	Com_Connections	-35.6249	0.0071	0.0233
17:00	0.7765	Com_Connections	-41.1773	0.0076	0.0088
18:00	0.6765	Com_Connections	-21.1558	0.0060	0.0231
19:00	0.6879	Com_Connections	-6.2102	0.0046	0.0210
20:00	0.6414	Com_Connections	10.9873	0.0031	0.0304
21:00	0.5206	Com_Connections	25.1907	0.0018	0.0672
22:00	0.2456	Res_Building	42.2174	0.0000	0.2581

Source: Energeia

Table E14 – Alice Springs, Maximum Demand, 5-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
12:00	0.7091	Total_Solar	49.7367	-0.0001	0.0735
13:00	0.0647	WPI	44.9240	1.0394	0.6795
14:00	0.3716	Com_Connections	15.0340	0.0028	0.2751
15:00	0.6682	Com_Building	42.1397	0.0000	0.0910
16:00	0.4551	Res_Connections	27.3211	0.0004	0.2116
17:00	0.5602	Population	-419.9770	0.0019	0.1456
18:00	0.6569	Population	-634.3956	0.0028	0.0962
19:00	0.5582	Population	-360.8270	0.0017	0.1467
20:00	0.5979	Population	-418.9207	0.0019	0.1251
21:00	0.4858	Res_Connections	30.1070	0.0003	0.1909
22:00	0.7166	Res_Connections	20.8556	0.0004	0.0705

Source: Energeia

Table E15 – Alice Springs, Maximum Demand, 7-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
12:00	0.7426	Com_Connections	Res_Connections	-64.6209	0.0040	0.0010	0.0282	0.0704
13:00	0.4694	WPI	Total_Solar	44.1583	1.8001	0.0000	0.2843	0.5852
14:00	0.7058	WPI	Res_Connections	6.4275	5.2054	0.0005	0.0547	0.2111
15:00	0.9140	WPI	Res_Connections	-37.3276	8.5045	0.0011	0.0031	0.0095
16:00	0.5742	WPI	Total_Solar	42.3003	7.2615	-0.0001	0.2913	0.3385
17:00	0.6083	Total_Solar	WPI	42.6773	-0.0001	7.4055	0.3057	0.2647
18:00	0.4756	WPI	Total_Solar	46.6489	4.8800	-0.0001	0.4286	0.3711
19:00	0.6879	Com_Connections	Res_Connections	-7.7319	0.0046	0.0000	0.0784	0.9794
20:00	0.6575	Com_Connections	Res_Connections	-6.6815	0.0035	0.0002	0.0728	0.6864
21:00	0.5437	Com_Connections	Res_Connections	11.5800	0.0021	0.0002	0.1219	0.6759
22:00	0.4064	Com_Connections	Res_Connections	10.6778	0.0012	0.0003	0.1741	0.3294

Source: Energeia

Table E16 – Alice Springs, Maximum Demand, 5-Year, Multi Variable Regression Statistics by Hour

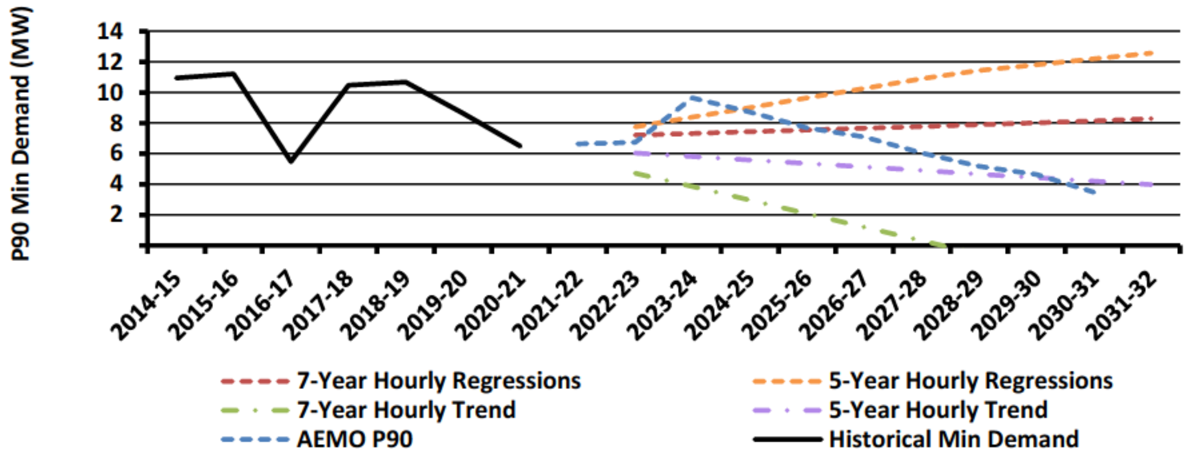
Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
12:00	0.7401	Res_Connections	WPI	-57.7000	0.0015	4.4982	0.1628	0.4526
13:00	0.0955	WPI	Total_Solar	45.1454	1.2260	0.0000	0.7079	0.8185
14:00	0.7789	WPI	Total_Solar	45.9507	3.0204	0.0000	0.1804	0.1620
15:00	0.9737	WPI	Total_Solar	47.6701	3.6342	-0.0001	0.0383	0.0150
16:00	0.5196	Total_Solar	Res_Connections	38.4225	0.0000	0.0002	0.6559	0.6486
17:00	0.6082	Population	Com_Connections	-365.2850	0.0016	0.0011	0.3232	0.6694
18:00	0.7050	Population	GSP	-742.4189	0.0032	0.0005	0.1658	0.6257
19:00	0.2682	Res_Connections	Res_Building	36.4282	0.0002	0.0000	0.6360	0.7738
20:00	0.4594	Res_Connections	Com_Connections	12.3499	0.0004	0.0012	0.3483	0.6455
21:00	0.1386	Population	Res_Building	-47.4789	0.0004	0.0000	0.8557	0.8889
22:00	None							

Source: Energeia

Output Range

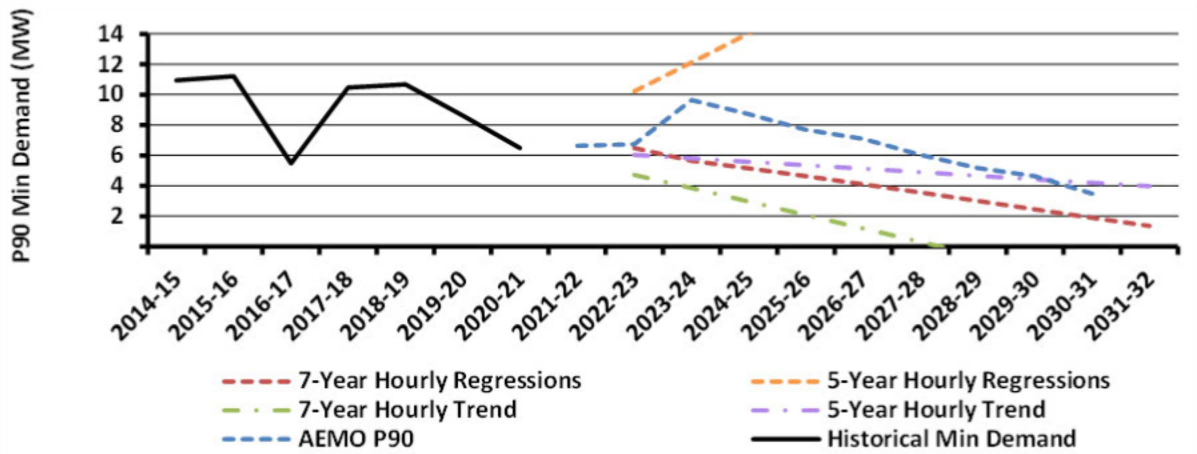
Minimum Demand

Figure E9 – Alice Springs, Minimum Demand, Single Variable Regression Forecast Range



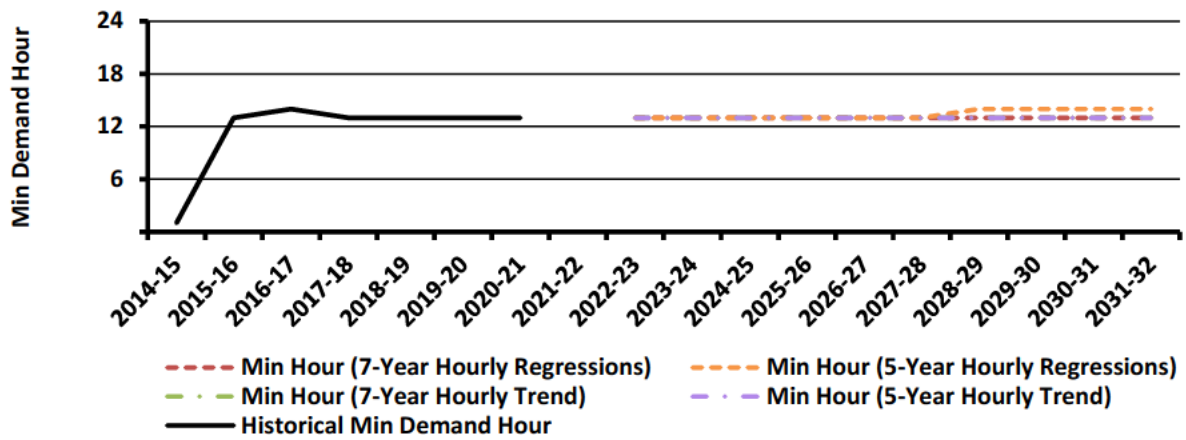
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E10 – Alice Springs, Minimum Demand, Multi Variable Regression Forecast Range



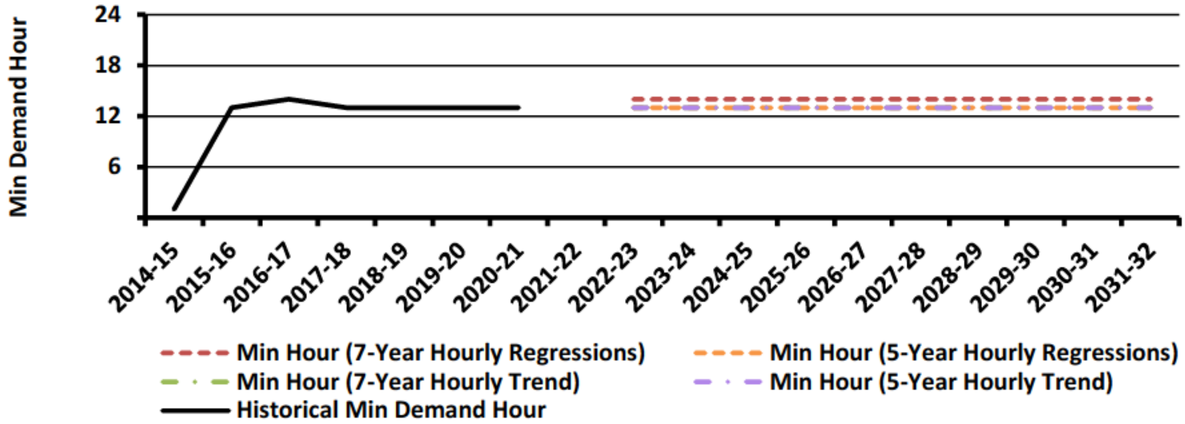
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E11 – Alice Springs, Minimum Demand, Single Variable Regression Hour Range



Source: Energeia

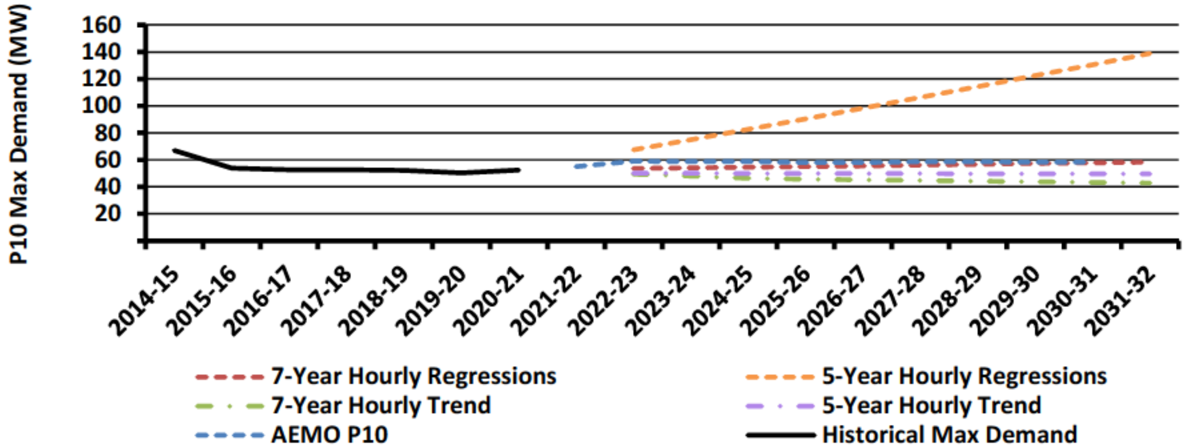
Figure E12 – Alice Springs, Minimum Demand, Multi Variable Regression Hour Range



Source: Energeia

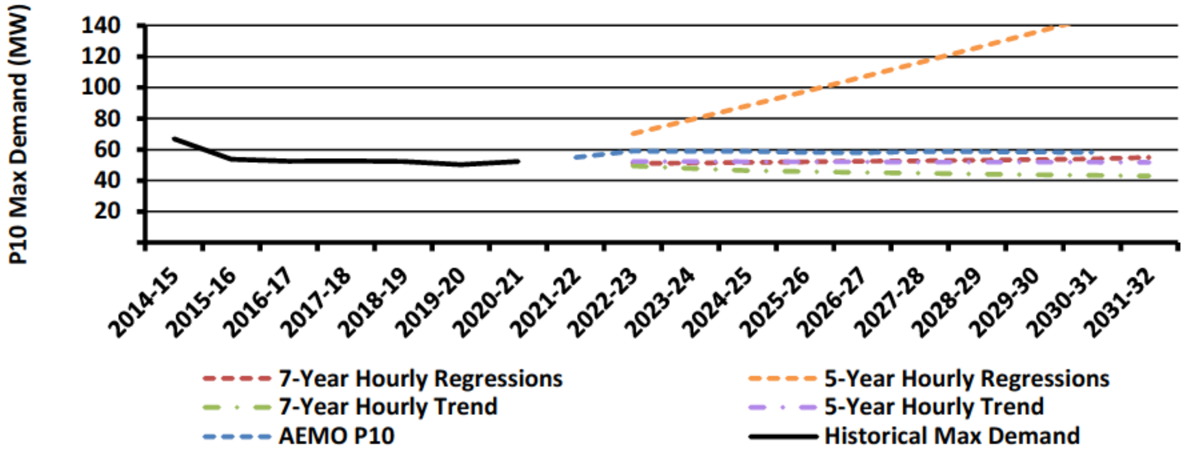
Maximum Demand

Figure E13 – Alice Springs, Maximum Demand, Single Variable Regression Forecast Range



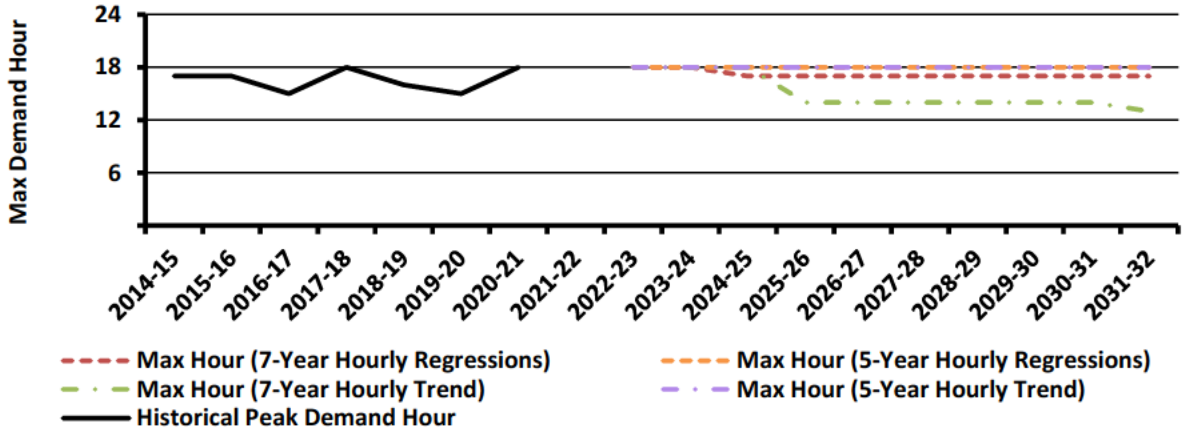
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E14 – Alice Springs, Maximum Demand, Multi Variable Regression Forecast Range



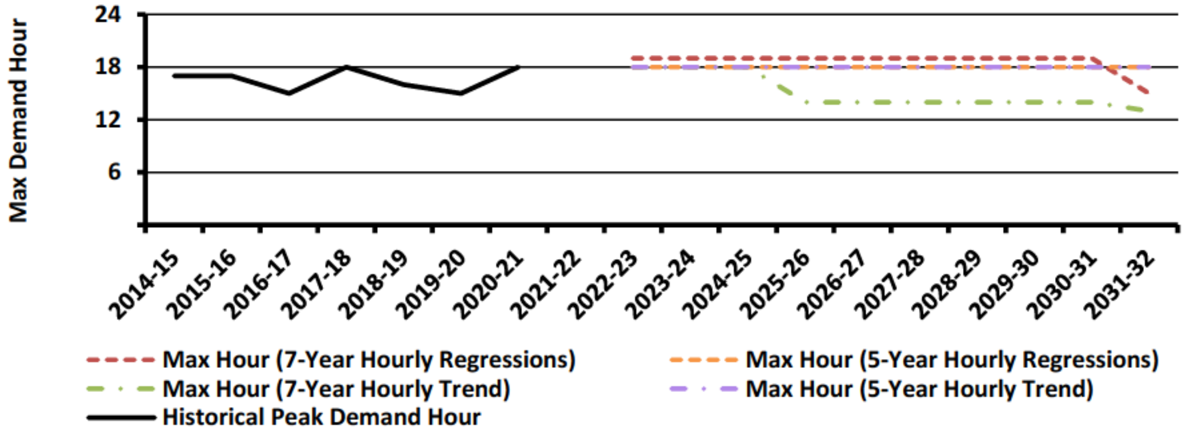
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E15 – Alice Springs, Maximum Demand, Single Variable Regression Hour Range



Source: Energeia

Figure E16 – Alice Springs, Maximum Demand, Multi Variable Regression Hour Range



Source: Energeia

Tennant Creek

Regression Parameterisation

Minimum Demand

Table E17 – Tennant Creek, Minimum Demand, 7-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
0:00	0.5020	Res_Connections	-4.978	0.00011	0.0747
1:00	0.5891	Res_Connections	-6.071	0.00013	0.0440
2:00	0.5667	Res_Connections	-6.755	0.00014	0.0508
3:00	0.7261	Res_Connections	-6.802	0.00014	0.0149
4:00	0.8012	Res_Connections	-7.457	0.00015	0.0065
5:00	0.7638	Res_Connections	-6.504	0.00014	0.0101
6:00	0.5268	Res_Connections	-2.237	0.00007	0.0648
7:00	0.4386	Total_Solar	2.526	0.00000	0.1051
8:00	0.4623	Total_Solar	2.580	-0.00001	0.0929
9:00	0.4299	Total_Solar	2.348	-0.00001	0.1098
10:00	0.3672	Total_Solar	2.158	-0.00001	0.1492
11:00	0.5241	Total_Solar	2.032	-0.00001	0.0658
12:00	0.6653	WPI	0.298	0.67931	0.0253
13:00	0.5228	WPI	0.078	0.73387	0.0664
14:00	0.2743	WPI	0.707	0.43662	0.2276
15:00	0.3084	Res_Connections	-2.180	0.00006	0.1956

Source: Energeia

Table E18 – Tennant Creek, Minimum Demand, 5-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
0:00	0.4958	Res_Connections	-4.175	0.00010	0.1843
1:00	0.6344	Res_Connections	-5.814	0.00012	0.1068
2:00	0.6418	Res_Connections	-6.851	0.00014	0.1032
3:00	0.7815	Res_Connections	-7.111	0.00014	0.0466
4:00	0.8766	Res_Connections	-8.216	0.00016	0.0191
5:00	0.8287	Res_Connections	-7.052	0.00014	0.0318
6:00	0.8324	Res_Connections	-2.897	0.00008	0.0307
7:00	0.6876	Com_Building	0.590	0.00001	0.0825
8:00	0.4312	Res_Connections	-2.372	0.00007	0.2287
9:00	0.3477	Res_Connections	-2.194	0.00007	0.2954
10:00	0.3943	Total_Solar	2.476	-0.00001	0.2567
11:00	0.3126	Res_Connections	-1.852	0.00006	0.3272
12:00	0.6644	WPI	0.152	0.75597	0.0927
13:00	0.5345	WPI	-0.198	0.88507	0.1605
14:00	0.3820	WPI	0.370	0.62144	0.2665
15:00	0.6346	Com_Building	0.306	0.00001	0.1067

Source: Energeia

Table E19 – Tennant Creek, Minimum Demand, 7-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
0:00	0.6897	Res_Connections	WPI	-9.0450	0.0002	0.4939	0.04	0.19
1:00	0.8930	Res_Connections	WPI	-11.6027	0.0002	0.6719	0.00	0.03
2:00	0.7383	Res_Connections	WPI	-11.3363	0.0002	0.5564	0.03	0.18
3:00	0.8782	Res_Connections	WPI	-10.6649	0.0002	0.4692	0.01	0.09
4:00	0.9910	Res_Connections	WPI	-11.9038	0.0002	0.5401	0.00	0.00
5:00	0.9326	Res_Connections	WPI	-10.3932	0.0002	0.4723	0.00	0.03
6:00	0.9603	Res_Connections	WPI	-6.1880	0.0001	0.4799	0.00	0.00
7:00	0.8513	WPI	Res_Connections	-6.2876	0.5683	0.0001	0.02	0.01
8:00	0.7590	Res_Connections	WPI	-6.6242	0.0001	0.6263	0.03	0.04
9:00	0.6355	Res_Connections	WPI	-6.3767	0.0001	0.6235	0.07	0.09
10:00	0.8429	Res_Connections	WPI	-9.2709	0.0002	0.8849	0.01	0.01
11:00	0.7674	WPI	Res_Connections	-6.7697	0.7057	0.0001	0.03	0.03
12:00	0.8414	WPI	Res_Connections	-4.7810	0.9424	0.0001	0.01	0.10
13:00	0.7002	Res_Connections	WPI	-6.1348	0.0001	1.0557	0.20	0.04
14:00	0.5569	WPI	Res_Connections	-5.7336	0.7702	0.0001	0.09	0.19
15:00	0.4078	Res_Connections	WPI	-4.3879	0.0001	0.2682	0.18	0.46

Source: Energeia

Table E20 – Tennant Creek, Minimum Demand, 5-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
0:00	0.8678	Res_Connections	WPI	-10.0622	0.0002	0.8258	0.07	0.14
1:00	0.9958	Res_Connections	WPI	-12.3210	0.0002	0.9128	0.00	0.01
2:00	0.7217	Res_Connections	WPI	-10.2855	0.0002	0.4818	0.17	0.53
3:00	0.8687	Res_Connections	WPI	-10.4937	0.0002	0.4745	0.08	0.37
4:00	0.9997	Res_Connections	WPI	-12.5114	0.0002	0.6026	0.00	0.00
5:00	0.9287	Res_Connections	WPI	-10.6014	0.0002	0.4979	0.04	0.24
6:00	0.9887	Res_Connections	WPI	-5.3941	0.0001	0.3503	0.01	0.03
7:00	0.8858	Res_Connections	WPI	-7.3368	0.0001	0.7038	0.06	0.11
8:00	0.7104	Res_Connections	WPI	-6.5975	0.0001	0.5928	0.16	0.30
9:00	0.5422	Res_Connections	WPI	-5.7611	0.0001	0.5003	0.26	0.45
10:00	0.8891	Res_Connections	WPI	-10.9560	0.0002	1.1464	0.06	0.08
11:00	0.6612	Res_Connections	WPI	-6.0534	0.0001	0.5894	0.19	0.29
12:00	0.9014	Res_Connections	WPI	-5.3882	0.0001	1.1398	0.16	0.05
13:00	0.7711	Res_Connections	WPI	-7.4229	0.0001	1.3857	0.29	0.12
14:00	0.7497	Res_Connections	WPI	-7.1100	0.0001	1.1397	0.23	0.13
15:00	0.8035	Res_Connections	WPI	-6.7705	0.0001	0.7710	0.11	0.14

Source: Energeia

Maximum Demand

Table E21 – Tennant Creek, Maximum Demand, 7-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
12:00	0.2668	Res_Building	5.9330	0.0000	0.2353
13:00	0.1177	Total_Solar	6.7733	0.0000	0.4512
14:00	0.1289	Res_Connections	4.9051	0.0000	0.4291
15:00	0.3608	Res_Connections	3.1456	0.0001	0.1538
16:00	0.2900	Res_Connections	3.0650	0.0001	0.2124
17:00	0.1980	Population	-7.7011	0.0001	0.3171
18:00	0.5285	Res_Connections	2.0897	0.0001	0.0642
19:00	0.4585	Res_Connections	0.7655	0.0001	0.0947
20:00	0.5115	Res_Connections	0.9570	0.0001	0.0708
21:00	0.5221	Res_Connections	-1.3800	0.0001	0.0666
22:00	0.4264	Res_Connections	-3.0798	0.0001	0.1118

Source: Energeia

Table E22 – Tennant Creek, Maximum Demand, 5-Year, Single Variable Regression Statistics by Hour

Hour	Best R^2	Variable	Intercept	Coefficient	P-Value
12:00	0.4315	Res_Connections	0.3871	0.0001	0.2285
13:00	0.2929	Res_Connections	0.6508	0.0001	0.3462
14:00	0.4709	Res_Connections	2.1672	0.0001	0.2008
15:00	0.4582	Res_Connections	1.3800	0.0001	0.2094
16:00	0.3895	Res_Connections	1.0668	0.0001	0.2605
17:00	0.2341	Population	-44.0002	0.0002	0.4089
18:00	0.3235	Res_Connections	2.8722	0.0001	0.3170
19:00	0.3568	Res_Connections	0.4797	0.0001	0.2875
20:00	0.3647	Res_Connections	1.2172	0.0001	0.2808
21:00	0.3789	Res_Connections	-0.3079	0.0001	0.2691
22:00	0.7314	Res_Building	4.1150	0.0000	0.0647

Source: Energeia

Table E23 – Tennant Creek, Maximum Demand, 7-Year, Multi Variable Regression Statistics by Hour

Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
12:00	0.3759	Res_Building	Res_Connections	2.4974	0.0000	0.0001	0.1957	0.4499
13:00	0.2233	Com_Connections	Res_Connections	-1.0003	0.0002	0.0001	0.3842	0.3949
14:00	0.3805	Res_Connections	Res_Building	3.1066	0.0001	0.0000	0.2237	0.2714
15:00	0.3904	Res_Connections	Res_Building	2.4041	0.0001	0.0000	0.1970	0.6821
16:00	0.3446	Res_Connections	Res_Building	1.9135	0.0001	0.0000	0.2239	0.5945
17:00	0.2536	Population	Res_Building	-20.6582	0.0001	0.0000	0.3742	0.6142
18:00	0.6199	Res_Connections	GSP	0.4054	0.0001	0.0001	0.0849	0.3822
19:00	0.4653	Res_Connections	GSP	0.1478	0.0001	0.0000	0.1412	0.8335
20:00	0.5200	Res_Connections	Population	-5.0885	0.0001	0.0000	0.3085	0.8033
21:00	0.4801	Population	Res_Building	-70.6838	0.0003	0.0000	0.1834	0.4524
22:00	0.6840	Population	Total Build	-137.8619	0.0006	0.0000	0.0463	0.1036

Source: Energeia

Table E24 – Tennant Creek, Maximum Demand, 5-Year, Multi Variable Regression Statistics by Hour

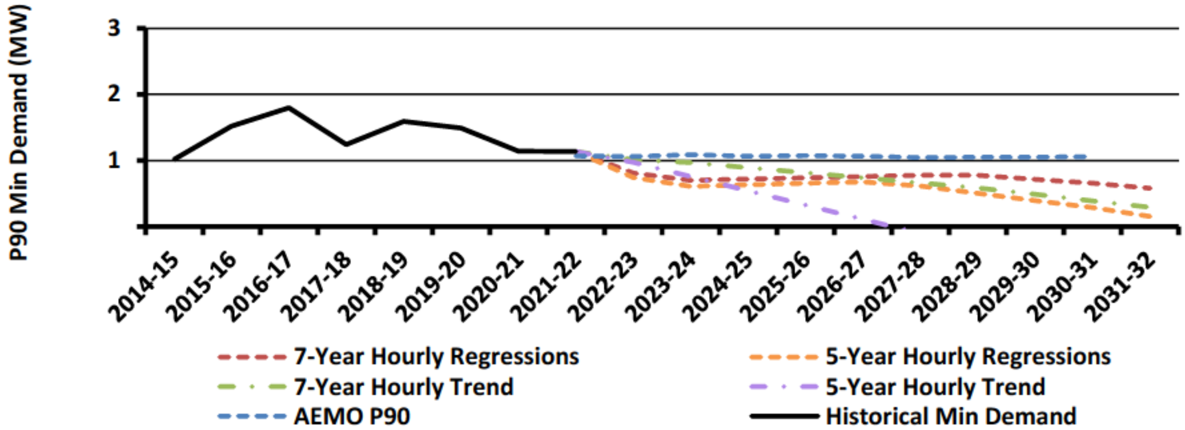
Hour	Best R^2	Variable1	Variable2	Intercept	Coefficient1	Coefficient2	P1	P2
12:00	0.4357	Res_Connections	GSP	-1.2553	0.0001	0.0000	0.4635	0.9140
13:00	0.0537	Total_Solar	Population	-1.4750	0.0000	0.0000	0.8386	0.9648
14:00	0.4712	Res_Connections	GSP	1.8147	0.0001	0.0000	0.4643	0.9748
15:00	0.6043	Res_Connections	GSP	-7.6279	0.0001	0.0002	0.2419	0.4807
16:00	0.4618	Res_Connections	GSP	-6.2104	0.0001	0.0002	0.3601	0.6558
17:00	0.2391	GSP	Population	-48.3205	0.0000	0.0002	0.9194	0.5311
18:00	0.5571	Res_Connections	GSP	-6.3400	0.0001	0.0002	0.2576	0.4123
19:00	0.4328	Res_Connections	GSP	-7.4790	0.0001	0.0002	0.3779	0.6563
20:00	0.4113	Res_Connections	Population	-37.6494	0.0001	0.0002	0.5963	0.7291
21:00	0.4068	Res_Connections	Com_Connections	-2.9766	0.0001	0.0002	0.3707	0.7878
22:00	0.8059	Com_Connections	Res_Connections	-14.1365	0.0010	0.0001	0.1798	0.1642

Source: Energeia

Output Range

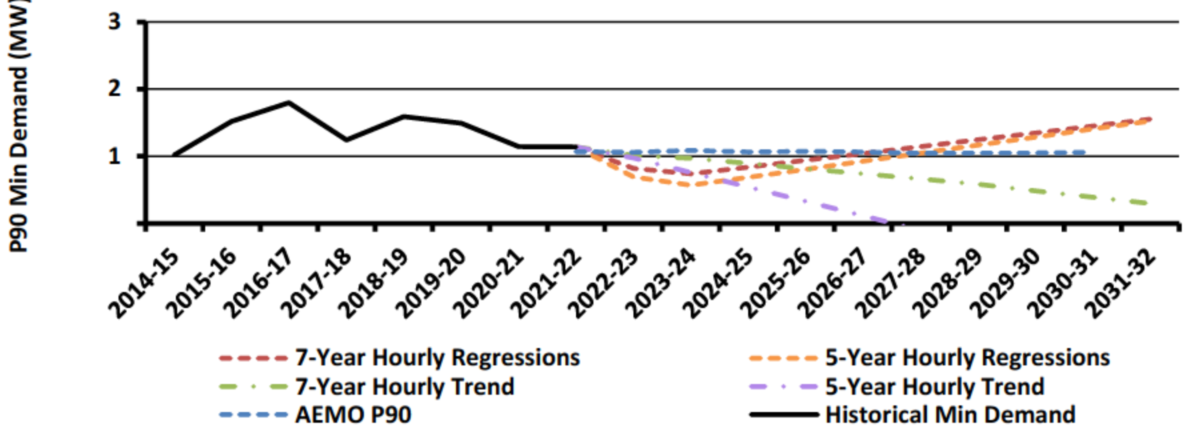
Minimum Demand

Figure E17 – Tennant Creek, Minimum Demand, Single Variable Regression Forecast Range



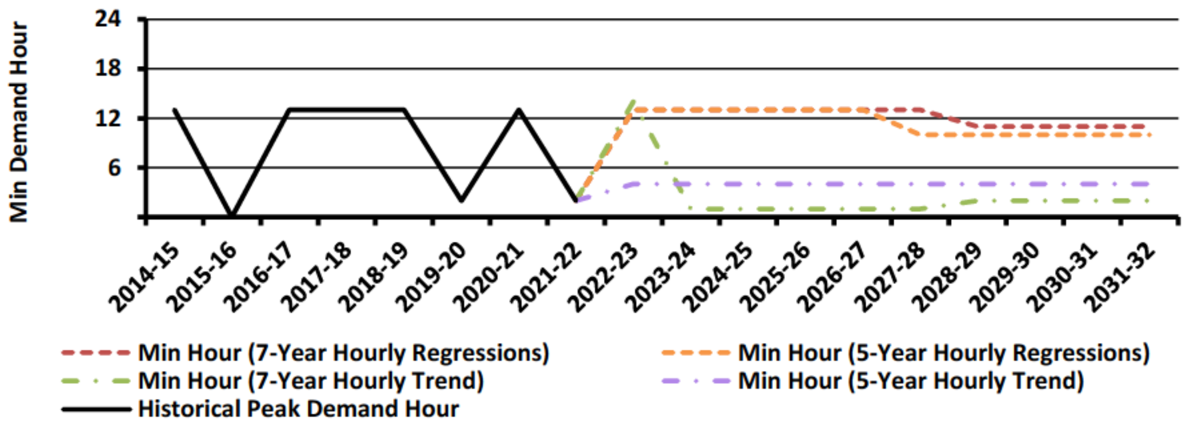
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E18 – Tennant Creek, Minimum Demand, Multi Variable Regression Forecast Range



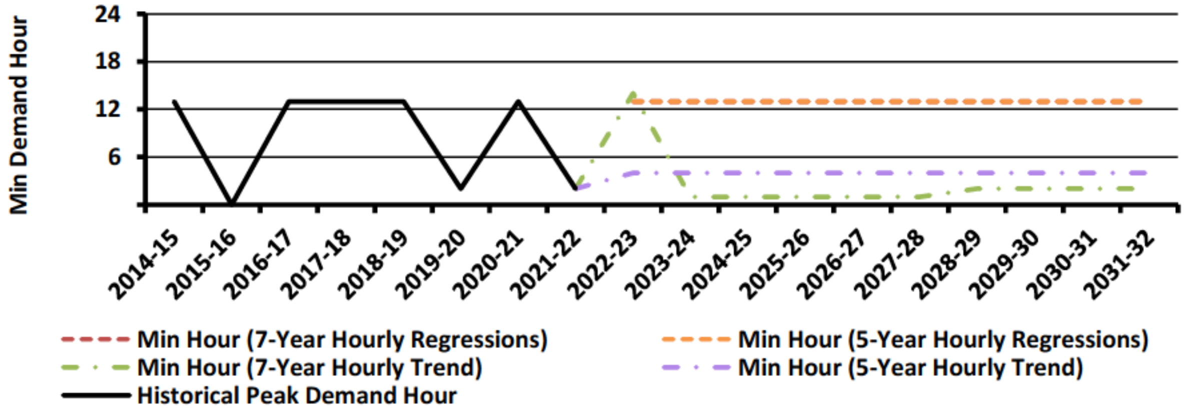
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E19 – Tennant Creek, Minimum Demand, Single Variable Regression Hour Range



Source: Energeia

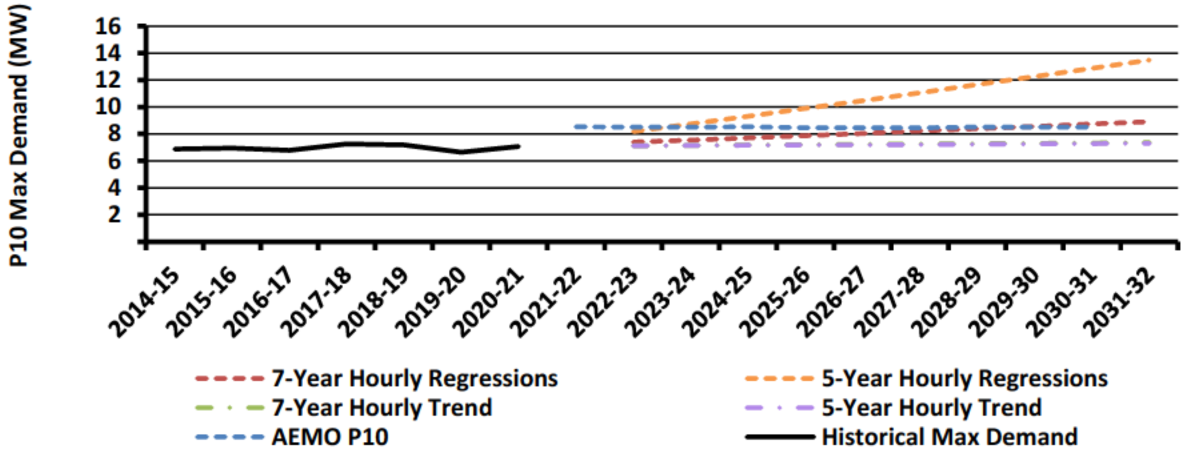
Figure E20 – Tennant Creek, Minimum Demand, Multi Variable Regression Hour Range



Source: Energeia

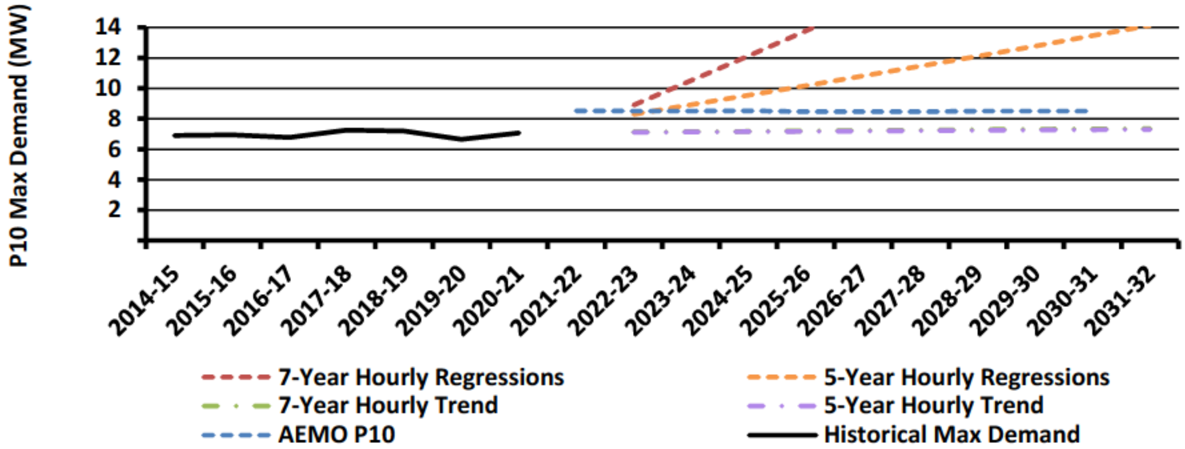
Maximum Demand

Figure E21 – Tennant Creek, Maximum Demand, Single Variable Regression Forecast Range



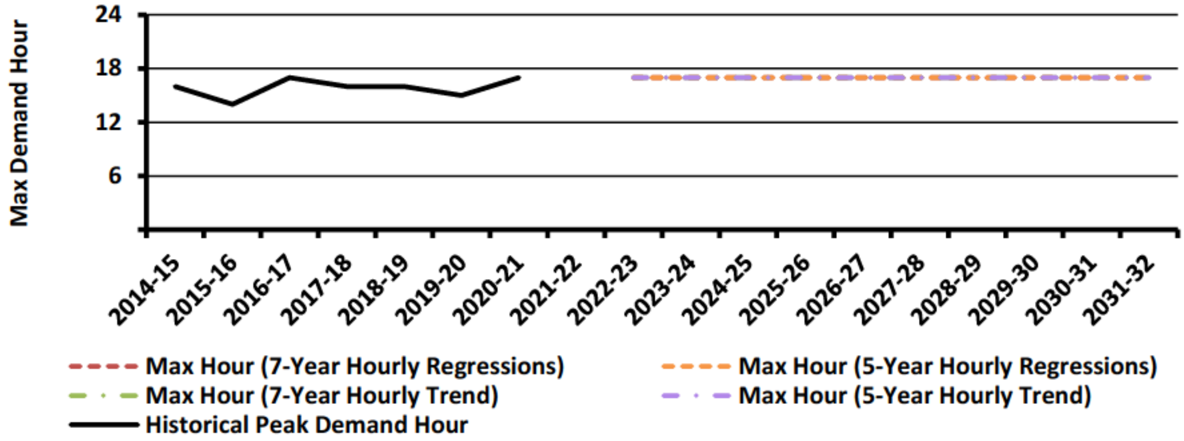
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E22 – Tennant Creek, Maximum Demand, Multi Variable Regression Forecast Range



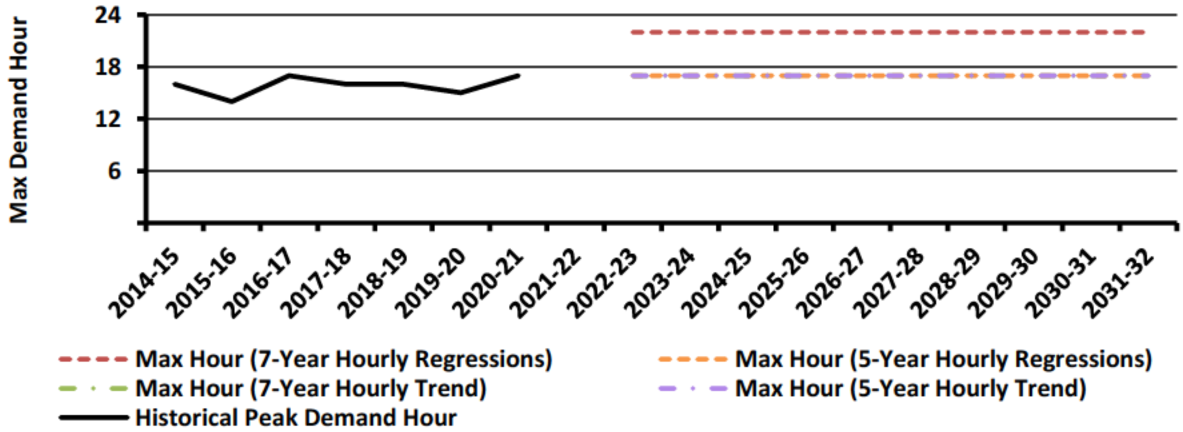
Source: Energeia Analysis, AEMO / NT Utilities Commission (2022)

Figure E23 – Tennant Creek, Maximum Demand, Single Variable Regression Hour Range



Source: Energeia

Figure E24 – Tennant Creek, Maximum Demand, Multi Variable Regression Hour Range



Source: Energeia

Appendix F – Industry Practice

Table F1 – Assessment of Demand Forecasts from Key Industry Participants

	NEM	VIC				NSW			QLD		ACT	SAPN	TAS	WA	NT
	AEMO	AusNet	Citipower. / Powercor.	Jemena	United	Ausgrid	Endeavour.	Essential	Energex	Ergon	EvoEnergy.	SAPN	Tas Networks.	Western Power	PWC
Target Variables															
Maximum Demand															
System	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Sub transmission	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-	✓
Zone Substation	-	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
HV Feeder	-	-	✓	✓	✓	-	-	-	-	-	-	-	-	-	✓
Minimum Demand															
System	✓	-	-	-	-	-	-	-	✓	✓	-	-	-	-	✓
Sub transmission	✓	-	-	-	-	-	-	-	-	-	-	✓	-	-	-
Zone Substation	-	-	-	-	-	-	-	-	✓	✓	-	✓	-	-	-
HV Feeder	-	-	-	-	-	-	-	-	✓	✓	-	-	-	-	-
Methodology															
Trend	-	✓	✓	✓	✓	-	✓	✓	-	-	-	-	-	-	Spatial
Probit / Logit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Multifactor Regression	✓	-	✓	✓	✓	✓	-	-	✓	✓	-	✓	✓	-	System
Autoregressive	-	-	-	-	-	-	-	-	-	-	✓	-	-	-	-
Machine Learning	✓	-	-	-	-	-	-	-	-	-	-	-	✓	-	-
Simulation	-	-	-	-	-	✓	-	-	✓	✓	-	✓	✓	✓	✓
Data Processing Steps															
Remove Bad Data	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-	✓
Remove Switching	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-	✓
Remove Weather	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Remove PV	✓	-	-	✓	-	✓	-	-	✓	-	✓	✓	✓	✓	✓
Remove Demand Mgt.	-	-	-	-	-	-	-	-	✓	-	-	-	-	-	-
Adjust for Major Loads	✓	✓	✓	✓	-	✓	✓	✓	✓	-	✓	✓	✓	✓	✓
Key Inputs															
Historical Trends															
Historical ADMD	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-	✓
Historical Sales	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-	✓

Forecast Weather															
Top 10 Days	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Spatial
Daily Max	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-
Multiple Data Points	✓	-	-	-	-	-	-	-	-	-	✓	-	-	-	System
Years of History	?	3-5	?	30	10	10	6	?	32	50	<1	12	?	18	15-30
Forecast GSP															
System	-	-	-	✓	✓	✓	-	-	✓	✓	✓	-	-	-	-
Spatial	-	✓	✓	-	-	-	-	-	-	-	✓	-	-	✓	-
Forecast Income															
System	-	-	✓	-	-	✓	-	-	-	-	-	-	-	-	-
Spatial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forecast Prices															
System	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spatial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Connection Applications															
All	-	✓	-	-	-	-	-	-	-	-	✓	-	-	-	-
Limited	✓	-	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓
Probabilistic	-	-	-	-	-	✓	✓	-	-	-	-	-	-	-	-
Forecast AC Units	-	-	-	-	✓	✓	✓	✓	-	✓	-	-	-	-	-
Forecast Energy Efficiency	-	-	-	-	✓	✓	✓	-	✓	-	-	-	-	✓	-
Forecast Solar PV	✓	-	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-
Forecast Electric Vehicles	✓	-	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	-	-
Forecast Batteries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Forecast Demand Management	-	-	-	-	-	-	-	-	✓	-	-	-	-	-	-
Quality Management															
Model Based on Best Fit	-	-	-	✓	-	✓	-	-	✓	✓	-	-	-	-	✓
Parameters Based on Best Fit	✓	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sensitivity Analysis	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Validated with Independent Forecast	-	-	✓	✓	✓	-	-	-	-	-	-	-	-	-	-
Aligns with Gov/AEMO Forecasts	-	✓	-	-	✓	-	-	-	-	-	-	✓	-	-	-
Accuracy Analysis	-	-	-	-	-	-	✓	✓	-	-	-	-	-	-	-
AER															
Approved	-	-	-	-	-	-	✓	✓	✓	✓	-	✓	✓	N/A	-

Source: Energeia, Various AEMO and DNSP Sources